

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:)
)
Georgia Power Company's 2025) Docket No. 56002
Integrated Resource Plan)

-and-

Georgia Power Company's 2025) Docket No. 56003
2025 Application for the)
Certification, Decertification)
and Amended Demand-Side)
Management Plan)

Consideration of Georgia Interfaith Power & Light and
Southface Energy Institute's Motion Challenging Georgia
Power Company's Trade Secret Assertions.

Hearing in Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, July 15, 2025

The hearing was called to order, pursuant to Notice
at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman - via Zoom
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner

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I N D E X

WITNESSES: DIRECT CROSS REDIRECT RECROSS

PIA STAFF:

**MICHAEL ROBINSON
RANDY HUBBERT
MATTHEW BOWERS**

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GIPL/Southface:

ROBERT PATRYLAK

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1 CHAIRMAN SHAW: Well, good morning again.
2 We'll get started. We have a hearing today. This
3 is Georgia Power's 2025 Integrated Resource Plan
4 and 2025 Application for Certification,
5 Decertification, and Amended Demand-side Management
6 Plan, Dockets 56002 and 56003: A motion
7 challenging Georgia Power Company's trade secret
8 assertion.

9 We'll start by calling for appearances.
10 Rather than going through the entire list of
11 intervenors in the docket, I'll just ask if
12 there's -- what parties are here, and if you would,
13 starting with Georgia Power and starting with the
14 Public Service Commission, just tell us who -- just
15 come up and we'll just see who we've got.

16 MR. COLLADO: Chris Collado, Public Service
17 Commission staff.

18 CHAIRMAN SHAW: Thank you. Georgia Power.

19 MR. HEWITSON: Good morning, Chairman. Steve
20 Hewitson and Holly Ingram on behalf of Georgia
21 Power Company.

22 CHAIRMAN SHAW: All right. And then we have
23 the SELC that filed the motion.

24 MS. WHITFIELD: Good morning, Commissioners.
25 Jennifer Whitfield, Bob Sherrier, and Aradhana

1 Chandra on behalf of Georgia Interfaith Power &
2 Light and Southface.

3 CHAIRMAN SHAW: Was there any other parties
4 that wanted to participate in this hearing?

5 (No response.)

6 CHAIRMAN SHAW: Okay. Are there any
7 housekeeping matters to take up at this point?

8 (No response.)

9 CHAIRMAN SHAW: I think the schedule is
10 pretty forthright in terms of what we're -- you
11 know, the oral arguments and the time limits. We
12 will allow witnesses, and beginning with Georgia
13 Power. But do we have any public witnesses that
14 wanted to provide public comment in relation to
15 this hearing?

16 (No response.)

17 CHAIRMAN SHAW: Okay. Hearing none, we'll
18 begin. If Georgia Power wants to call -- do you
19 have any witnesses you want to call up?

20 MR. HEWITSON: I do, Mr. Chairman.

21 CHAIRMAN SHAW: At this time, I'll let you do
22 that and swear them in.

23 MR. HEWITSON: All right. Georgia Power
24 calls Mr. Michael Robinson, Mr. Randy Hubbert, and
25 Mr. Matthew Bowers to the stand.

1 CHAIRMAN SHAW: Okay.

2 MR. HEWITSON: If you could remain standing
3 and raise your right hands. Gentlemen, do you
4 swear that the testimony you are about to give is
5 the truth, the whole truth, and nothing but the
6 truth, so help you God?

7 THE PANEL: Yes.

8 MR. HEWITSON: Thank you.

9 Thereupon,

10 MICHAEL ROBINSON,
11 RANDY HUBBERT,
12 MATTHEW BOWERS,

13 having been duly sworn, testified as follows:

14 DIRECT EXAMINATION

15 BY MR. HEWITSON:

16 Q. Okay. I believe the Commission is familiar
17 with each of these gentlemen, but just in case, let's go
18 ahead and have them introduce themselves. I'll start from
19 my left. Mr. Robinson, would you please introduce
20 yourself and give your roles and responsibilities for the
21 company?

22 A. (Witness Robinson) Yes. Good morning,
23 Commissioners. Mike Robinson, vice president of grid
24 transformation for Georgia Power Company. And my team is
25 responsible for planning, policy, and transmission
distribution for Georgia.

1 A. (Witness Bowers) Good morning, Commissioners.
2 My name is Matthew Bowers. I'm the IRP project manager
3 for Georgia Power. I led the end of the 2022 IRP, but
4 also the development, defense, and implementation of the
5 2023 IRP update and the 2025 IRP.

6 A. (Witness Hubbert) Good morning,
7 Commissioners. My name is Randy Hubbert. I'm director of
8 resource planning for Southern Company Services. My team
9 supports Georgia Power and the sister operating companies
10 with their integrated resource planning efforts.

11 Q. Gentlemen, to expedite the presentation of
12 your testimony and your explanation of these documents,
13 I'm going to skip straight to the documents that are
14 attached as exhibits to give this motion. And I'll ask
15 each of you in turn regarding the specific documents.

16 If we look at -- and I believe the Commission
17 probably has a copy of GIPL's motion, so I will refer to
18 them -- in order to avoid disclosure of any trade secret
19 information this morning, I'll refer to them as their
20 exhibit numbers and give a short explanation, if I can,
21 about the specific document. So the first one is
22 Exhibit 2A to GIPL's motion, and then Miss -- and that is
23 part of the 2025 IRP Financial Review, that was marked as
24 trade secret in the original filing in the IRP.

25

1 Mr. Hubbert, I believe that document is your
2 responsibility.

3 (The documents referred to were premarked for
4 identification as GIPL/Southface Exhibit 2A.)

5 A. (Witness Hubbert) Sure. So, yes, the
6 financial review document is a document that's filed.
7 It's a required filing in each of the IRPs that Georgia
8 Power files, the triennial IRPs. It provides a look at
9 several things. It has detailed Aurora modeling
10 information that is used, along with financial parameter
11 information that is used, to look at relative rate impacts
12 across a number of scenarios that Georgia Power is
13 required to file in their IRP, including the base case.
14 And then other scenarios that look at higher gas prices,
15 price on carbon, and other future scenarios, as required
16 in the IRP rules.

17 Q. Okay. Why would it be harmful if the
18 information that's been marked as trade secret in the
19 company's file would be disclosed publicly?

20 A. (Witness Hubbert) So there's two reasons:
21 One, showing the relative rate impacts could provide
22 insights into the rate for which Georgia Power would use
23 in its discussions with potential new customers coming to
24 the state. So it could disadvantage Georgia Power in
25 competing for new customer growth and economic growth in

1 the state of Georgia.

2 The other part that could be hurtful is, as I
3 mentioned, there's detailed Aurora analysis that's used in
4 this -- in this document -- to support this document.
5 Some of that detailed analysis provides insights into the
6 company's revenue requirements for new generation
7 development.

8 Someone could use that information to tailor
9 a bid in the many RFPs that Georgia Power issues for its
10 customers to better know the company's cost and could
11 raise their price of their bid up to the company's cost
12 and increase cost to customers.

13 Q. What does the company do to maintain the
14 secrecy of this information?

15 A. (Witness Hubbert) A number of things. One,
16 as you can see during the IRP proceedings, we mark
17 everything trade secret, protect that information as trade
18 secret, in creating both trade secret versions and public
19 disclosure versions of the documentation.

20 Within the company ourselves, we have
21 different technology frameworks and we segment who can
22 have access to certain networks. So we segment access
23 control internally. And also, we limit -- even for those
24 that can have access to that information, we limit this
25 information to those that really need to know the

1 information.

2 Q. Thank you, Mr. Hubbert.

3 (The documents referred to were premarked for
4 identification as GIPL/Southface Exhibit 3A.)

5 (The documents referred to were premarked for
6 identification as GIPL/Southface Exhibit 4A.)

7 I want to turn to Exhibit 3A, and I'm going
8 to group that with Exhibit 4A. Exhibit 3A is the external
9 peak adjustment for large loads. And Exhibit 4A is the
10 winter coincident demand with adjustments by class.

11 Mr. Bowers, I believe these are your documents. If you
12 could give a brief overview or explanation, what
13 information is contained in the trade secret portions of
14 these documents?

15 A. (Witness Bowers) Sure. Commissioners,
16 Exhibit 3A contains the risk adjusted loads that Georgia
17 Power expects from its large load pipeline. So as you're
18 aware, and as we've explained in the 2023 IRP update, as
19 well as the 2025 IRP, the company takes the announced load
20 from customers, and we run that through the company's
21 proprietary load realization model, adjusting for various
22 stages of each of the projects. For example, has a
23 project selected the state, has the project selected an
24 electric service provider, what kind of project is this?
25 Is this a hyperscaler, a data center developer, with or

1 without tenants? Is this an industrial customer? And
2 then we adjust for load ramp delays as well as load
3 materialization. And so that's -- those are the
4 adjustments that are made within our proprietary load
5 realization model that produces the risk adjusted loads
6 that are shown on this page.

7 Q. And why would it be harmful to customers and
8 to Georgia Power if this information was released
9 publicly?

10 A. (Witness Bowers) Disclosure of this
11 information, Commissioners, would harm Georgia Power's
12 ability to procure the best pricing for its customers. It
13 would also effectively slow -- could effectively slow
14 economic growth for the state of Georgia. As you're
15 aware, we compete. Even though we're the only regulated
16 electric utility in the state of Georgia, that doesn't
17 mean we don't compete for load.

18 So within the state, we compete with 41 EMCs,
19 as well as 52 municipalities. And so we compete for large
20 loads, that is, loads that are 900kW or greater, through
21 customer choice and the Georgia -- Georgia Territorial
22 Electric Service Act. And so we -- we compete internally
23 with a significant number of electric service providers
24 within the state. But we also compete for economic
25 development projects with other states and with electric

1 service providers and utilities across the country. So
2 it's clear Georgia Power, even though we're regulated --
3 the only state-regulated electric utility, we compete
4 within the state and across the country.

5 Disclosing this information, the
6 risk-adjusted loads, because we've also provided the
7 announced loads of these projects in our quarterly large
8 load economic development reports, competitors could back
9 into a risk adjustment factor that we produced through
10 that proprietary load realization model, and effectively
11 better plan for large loads and better price -- make
12 better pricing offers to those large loads, so that --
13 that would effectively erode Georgia Power's competitive
14 position. And it harms our ability to obtain the best
15 pricing for our customers, as well as for the state of
16 Georgia. It could lead to potentially fewer economic
17 development project wins by the company, potentially fewer
18 for the state. And so that could have the effect of
19 slowed economic growth for the -- for the state of
20 Georgia. Okay.

21 COMMISSIONER PRIDEMORE: Mr. Bowers, can you
22 better define "best pricing for customers"? Best
23 pricing of what?

24 MR. BOWERS: The best pricing of the
25 individual customer choice project that we're

1 pursuing.

2 BY MR. HEWITSON:

3 Q. Mr. Bowers, I want to skip the third question
4 with respect to Exhibit 3A, because I believe the answer
5 to that will be the same as 4A, so I'm going to allow you
6 to combine those. But with the Exhibit 4A, could you
7 please explain what that information -- or the trade
8 secret portion of that information provides?

9 A. (Witness Bowers) Yes. The trade secret
10 information in Exhibit 4A is class specific load
11 information. So, for example, it shows the breakdown of
12 our aggregate load forecast, which we do disclose
13 publicly. But this is -- the trade secret portion is the
14 breakdown by class level. So we have residential,
15 industrial, commercial classes, as well as government and
16 MARTA.

17 So this information is marked as trade secret
18 throughout the filing, and it's trade secret for many of
19 the same reasons as Exhibit 3A, but this provides further
20 specificity at the class level. So if this information
21 were disclosed publicly, when combined with other public
22 information that's available for the class and segment of
23 the large loads that we've provided in data requests, and
24 the announced loads that we've provided in quarterly large
25 load economic development reports, this information could

1 be used to tailor better offers to commercial and
2 industrial customers.

3 Q. And how would that be harmful to customers if
4 those offers are tailored in a different manner based on
5 the disclosure of this information?

6 A. (Witness Bowers) This could improve
7 competitors' relative position, competitive position, and
8 customer choice offers, specific to commercial and
9 industrial customers. So for commercial, that would be
10 projects like data centers, and industrial is something
11 like a battery manufacturer.

12 Q. And would you say disclosure of this
13 information, which has been developed by Georgia Power in
14 a proprietary model, would erode Georgia Power's
15 competitive position with respect to these economic
16 development projects?

17 A. (Witness Bowers) Yes, it would.

18 Q. With respect to Exhibits 3A and 4A, what does
19 the company do to maintain the secrecy of that trade
20 secret information?

21 A. (Witness Bowers) Similar to Mr. Hubbert's
22 response, we mark this information as trade secret in our
23 filings. It's clearly -- it's highlighted in yellow to
24 indicate its trade secret nature. It's redacted in the
25 public disclosure versions. And, similarly, on an

1 internal basis, we protect access to the information on a
2 need-to-know basis. Shared drives are managed by the --
3 at a department level. Also, our team sites that we use
4 to cooperate, collaborate across the company, access to
5 those sites is managed to prevent unauthorized access.

6 And we also take -- we have internal training
7 within Southern Company on records management, data
8 privacy. We also conduct specific trade secret and
9 attorney-client training that's conducted by our counsel
10 ahead of each IRP filing.

11 Q. And when you say "unauthorized access," do
12 you mean both virtual and physical access to the
13 information?

14 A. That's correct. Specifically as it relates
15 to Southern Power, which is an affiliate of Southern
16 Company. According -- in accordance with FERC orders, we
17 must maintain virtual and physical and functional
18 separation from Southern Power, so they're -- they're
19 located on different floors. They have -- we have batched
20 access to our information.

21 And then from a virtual standpoint, our
22 information is completely separated from anyone at
23 Southern Power Company so that they cannot access this
24 information because, you know, FERC put these protections
25 in place because information such as resource planning

1 information can provide a competitive advantage if not
2 disclosed to others at the same time.

3 Q. And does Georgia Power additionally track
4 access -- track who accesses this information to ensure
5 that compliance with its procedures and policies with
6 respect to the limitation of access to this information is
7 adhered to by its employees?

8 A. (Witness Bowers) Yes, we limit access to
9 individual employees, but we also go further than that.
10 Within IRP proceedings, intervenors and Commission staff
11 will request certain information that is trade secret, and
12 we host that information on a share file site or an FTP --
13 a file transfer protocol site where we have individualized
14 credentials and access to the trade secret information,
15 and that information is additionally only available during
16 that specific docket, after which we remove the
17 information and remove access to the trade secret info.

18 Q. Thank you, Mr. Bowers.

19 MR. HEWITSON: Moving on, I should have
20 announced during a housekeeping matter that GIPL
21 has informed me that they have withdrawn their
22 challenge to Exhibits 5A and 7A, so I will skip
23 those this morning and go to 6A.

24 (The documents referred to were premarked for
25 identification as GIPL/Southface Exhibit 6A.)

1 BY MR. HEWITSON:

2 Q. Mr. Hubbert, back to you. This is the
3 technology, cost, and performance summary. Could you
4 please give a brief explanation of what this information
5 contains?

6 A. (Witness Hubbert) Sure. So the technology
7 cost performance information is actually a piece of a
8 larger document that's included in the IRP filing, which
9 is the resource mix study. So in the resource mix study
10 document, we're covering all of the assumptions that go
11 into the expansion analysis for the company and the
12 system. And a piece of that is the future generation
13 technology that we make available to the modeling to be
14 selected to meet the company's and the system's future
15 capacity and energy needs. So Table 5 specifically lays
16 out each generation technology that we allow the model to
17 select, as well as its -- each technology's cost and
18 performance information.

19 Q. Mr. Hubbert, why is it important for the
20 company to have as precise of information with respect to
21 these technology and performance costs as possible?

22 A. (Witness Hubbert) So during the IRP, we spoke
23 about this. So there's really a few things that's really
24 important about the resource mix study. Number one, it
25 does provide an indication to the company of what types of

1 resources would be economic for customers' future capacity
2 and energy needs. So it is very indicative of the types
3 of resources that we would solicit or seek to -- seek to
4 propose as a company-owned proposal.

5 But two, a very important piece of it is:
6 These cases, along with all the existing resources -- or
7 sorry -- the expansion plan resources, along with existing
8 resources, are used in production cost modeling and a key
9 deliverable or data point from that are the avoided energy
10 costs. Those are used to evaluate all of our supply side
11 and demand side decisions for the upcoming year. And this
12 is a moment where we're making significant resource
13 decisions with, I think, 13 gigawatts of active RFPs for
14 capacity resources and solar resources via utility scale
15 RFPs or distributed generation RFPs. So it's really
16 important that we have as accurate information as possible
17 when making those -- that scale and magnitude of decisions
18 for the company.

19 Q. Can you help explain why it would be harmful
20 to Georgia Power and its customers if this information was
21 disclosed publicly?

22 A. (Witness Hubbert) Sure. So, Commissioners,
23 where the harm could be -- the potential harm could be
24 would be that if we disclosed our costs and the market has
25 that information, when we conduct an RFP, we expect each

1 of the bidders to provide us their best proposal, and they
2 know they have to compete with other bidders and have to
3 compete with the company for the capacity or energy
4 resources that are going to be deployed.

5 If they have information for -- our
6 information, for our generation technology costs, they
7 could raise their price to just below our cost, which
8 would actually hurt customers, because it doesn't give us
9 their best bid into the RFPs.

10 Q. Would customers end up paying more for
11 resources -- would Georgia Power and customers end up
12 paying more for resources through those RFPs if that were
13 to happen?

14 A. (Witness Hubbert) That is correct.

15 COMMISSIONER MCDONALD: Help me -- when you
16 say that customer -- that competing customer might
17 raise their price just below Georgia Power's,
18 wouldn't they know that they were below Georgia
19 Power before they raised it? I mean, why would
20 they -- they would raise it to get the bid, I
21 guess, at a lower -- at a greater cost of profit to
22 them than it would be on their original bid; is
23 that right?

24 MR. HUBBERT: That's correct.

25 COMMISSIONER MCDONALD: But when do you know

1 that information that they've raised that?

2 MR. HUBBERT: Well, we wouldn't know for
3 certain, but it's the potential risk that they
4 could do that. Having that information would
5 allow -- give them the insight to be able to do
6 that, which could be hurtful to Georgia customers.

7 COMMISSIONER MCDONALD: Public notice and
8 then those that qualify for information on the
9 trade secret notices, would they be under that
10 category or because they are a competing customer,
11 they are automatically not privileged to trade
12 secret information?

13 MR. HUBBERT: That's right. So during this
14 proceeding -- I think Mr. Bowers just spoke to
15 this. So, yes, those that sign an NDA, or
16 non-disclosure agreement, can have access to the
17 information during the proceeding --

18 COMMISSIONER MCDONALD: But you even there
19 can restrict some of it; isn't that right?

20 MR. HUBBERT: Even there, that's right. If
21 it's a competing customer, we can -- we can segment
22 who has access to that information. And we would
23 not allow a competing customer to have that
24 information, even during this proceeding.

25 MR. BOWERS: And, in fact, to add to that,

1 Mr. Hubbert and Commissioner McDonald, we have in
2 the 2025 IRP proceeding limited trade secret
3 information, and distinguished between whether an
4 intervenor is a potential developer and, therefore,
5 competitor with the company versus one who's not.

6 BY MR. HEWITSON:

7 Q. And information was not provided --
8 information related to technology costs and other
9 information that they could use to manipulate their bids
10 was not provided to intervenors who might also be bidding
11 into RFPs; is that right, Mr. Bowers?

12 A. (Witness Bowers) That's correct.

13 Q. What else -- other -- in addition to marking
14 it as trade secret, maintaining it as trade secret, in the
15 normal course of business, what does Georgia Power and
16 Southern Company as a whole do to maintain the secrecy of
17 this data, Mr. Hubbert?

18 A. (Witness Hubbert) So much like the response
19 to the first question, we market it as trade secret. We
20 highlight it yellow in these proceedings to make sure it's
21 very obvious that it is trade secret and the public
22 disclosures, it's redacted. The IT networks or technology
23 networks, we segment those. So it's everything that I
24 said in the first response and what Mr. Bowers added in
25 his response.

1 Q. Okay. Thank you.

2 (The documents referred to were premarked for
3 identification as GIPL/Southface Exhibit 8A.)

4 Skipping to Exhibit 8A, Mr. Robinson. These
5 are the estimated transmission costs for project level
6 costs. Could you explain what's shown on Exhibit 8,
7 please?

8 A. (Witness Robinson) Yes, Commissioners. This
9 exhibit includes all the project details for all the
10 projects that are in the ten-year plan for the ITS, so the
11 Integrated Transmission System. It includes information
12 on location of projects. So the zone ID of where it is in
13 the state, the year that it's identified in the ten-year
14 plan. What we call the teams number, teams is our
15 estimating system. It's explained in Volume 3. The
16 project name, which often gives start and end location,
17 particularly talking about transmission lines, the
18 specific need date that's identified for that project in
19 the previous ten-year plan -- so the '24 need date is
20 defined. And then -- or correct that. That's for this
21 ten-year plan is the need date that's specifically
22 identified.

23 The sponsor of the project, so that's either
24 GTC, MEAG, Dalton Utilities, Georgia Power ITS, or Georgia
25 Power non-ITS, because there are areas in the state where

1 Georgia Power serves there that are not -- that are not in
2 the Territorial Act, say, Savannah. The estimated cost
3 for Georgia Power Company, the estimated cost for Georgia
4 Transmission Corporation, the estimated cost for MEAG, the
5 estimated cost for Dalton Utilities, and the total cost of
6 the project.

7 Q. And what is identified as trade secret are
8 those columns that include the cost, not necessarily the
9 project identifier information; is that correct,
10 Mr. Robinson?

11 A. (Witness Robinson) Yes. So the five columns
12 specific to cost, each of the four participants and the
13 total cost.

14 Q. Okay. And why would it be harmful to Georgia
15 Power and its customers if the cost information on a
16 project level was provided for these transmission
17 projects?

18 A. (Witness Robinson) Well, Commissioners, one
19 thing that's important to point out is 44 percent of this
20 plan is not Georgia Power specific. So these are projects
21 that are sponsored by GTC, MEAG, or Dalton Utilities.
22 Georgia Power cannot disclose that information.

23 The other thing is, as Mr. Bowers talked
24 about, we do have competition in the state as it relates
25 to customer choice, and as well as competing outside of

1 the state and economic development to bring projects to
2 Georgia. Knowing the cost specific to customer-related
3 projects would give a competitive advantage to other
4 utilities competing for those opportunities.

5 We also bid out our transmission and
6 substation construction work. So those entities that are
7 bidding into those bids or those RFPs would have a
8 competitive advantage on our -- they could back into our
9 costs or estimate that we're using as it relates to
10 transmission cost per line mile or substation costs that
11 we're estimating. And so that's another reason that we do
12 not disclose that.

13 And then it's also consistent with how we
14 handle this information at SERTP, so the Southeastern
15 Regional Transmission Planning process. We do not
16 disclose project-specific costs. Indicative cost is
17 available if you sign an NDA, so cost per line mile or
18 cost to build a 500kV station, but we do protect that
19 information under a non-disclosure agreement.

20 And then the other thing that I think is most
21 important is, with the project specific information, you
22 can back into our transmission marginal cost. So in
23 Technical Appendix Volume 3, we define how we calculate
24 our transmission marginal cost. But we do not give the
25 inputs into that calculation. By having this information,

1 you can back into those inputs and calculate our
2 transmission marginal cost, which goes into our
3 competitive pricing. That's very important. That would
4 give an economic benefit to other utilities throughout the
5 United States, as well as utilities internal to Georgia.

6 Q. Okay. And Mr. Robinson, does the --

7 COMMISSIONER PRIDEMORE: Mr. Hewitson, would
8 it give a benefit to suppliers of materials of the
9 transmission system?

10 MR. ROBINSON: Yes, Commissioner, it could,
11 specifically to transformer manufacturers,
12 companies like Quanta or Pike that provide line
13 resources to us, or other material, like breakers
14 or transmission structures. You could back into
15 that cost with this information.

16 COMMISSIONER PRIDEMORE: Wires?

17 MR. ROBINSON: Wires, too, with the line
18 miles. If you knew enough specifics about the
19 project, you could -- you could calculate into our
20 costs for conductive as well.

21 BY MR. HEWITSON:

22 Q. And with the recent changes to the rules and
23 regulations to address large loads, Mr. Robinson, how
24 would the disclosure of this information impact Georgia
25 Power's ability to compete for economic development

1 projects against other states?

2 A. (Witness Robinson) Well, that -- as I
3 mentioned, that transmission marginal cost that we
4 calculate is an input into that minimum build calculation,
5 as it relates to the new rules and regs.

6 Q. Okay. And the rules and regs require the
7 large load customer to pay for its share of the costs,
8 which would be included -- which would be set forth in
9 publicly disclosed information. Would it hinder Georgia
10 Power's ability to compete for those projects and
11 negotiate with those large loads?

12 A. (Witness Robinson) It certainly could.

13 Q. Mr. Hubbert, sorry to do this to you, but I
14 wanted to go back and ask you another question.

15 A. (Witness Hubbert) Okay.

16 Q. Because during -- you were one of the
17 witnesses in the IRP who had to handle these questions,
18 and during the IRP, there was testimony from other
19 witnesses in the proceeding about other utilities in the
20 country that disclose the generic pricing or their
21 expected costs of generation and performance data, and I
22 wanted to point that out to you and ask you why Georgia
23 Power treats that information different than these other
24 companies who disclose this information publicly.

25 A. (Witness Hubbert) Yeah. So first, let me

1 just touch on the other companies. I can't really speak
2 to why they do that. I know they have different
3 regulatory requirements, different legislative
4 requirements. Some are in different market structures
5 than we're in. Some may or may not have RFP rules, and
6 then even within that, carve-outs for company-owned
7 proposals or not. I cannot speak to all those details. I
8 just know for us, back to what I stated earlier, the
9 importance of these expansion plans, and when they're used
10 to make billion upon billion-dollar decisions, it's
11 important to us to have as precise information as we can
12 get that's kind of tailored to our system, that's site
13 specific or region specific, because we're using it to
14 make those significant resource decisions, both on the
15 supply side and the demand side.

16 Q. Thank you, Mr. Hubbert.

17 MR. HEWITSON: Gentlemen, thank you for your
18 time.

19 Mr. Chairman, I will turn them over for
20 cross-examination unless there are further
21 questions from the Commission.

22 COMMISSIONER JOHNSON: Just a quick question.
23 You mentioned -- and thank you for coming. You
24 mentioned the non-disclosure statements that are
25 signed. Mr. Hewitson, you might be able to answer

1 this as well. How often do you have a breach of a
2 non-disclosure statement?

3 MR. ROBINSON: I don't have access to that
4 information. We do a lot to protect that
5 information internally, as well as with other
6 companies when we're talking details on cost, to
7 sign non-disclosure agreements to protect that
8 information. There are legal provisions in those
9 non-disclosure agreements for indemnity, as well as
10 damages for disclosing that information.

11 COMMISSIONER JOHNSON: Yeah, I would imagine
12 you sign hundreds -- maybe thousands. I just
13 wondered, have we ever had to go after anybody for
14 a breach?

15 MR. HEWITSON: Not while I've been doing this
16 representation, Commissioner Johnson. Those
17 non-disclosure agreements are there for a reason,
18 and they're there to protect the information, and
19 it's exactly what the company does. And we are
20 vigilant about how we protect that information,
21 even having database websites that are password
22 protected to ensure that only those individuals who
23 have signed the NDAs have access to that
24 information and can download that information. So
25 it's done very particularly, very carefully, to

1 ensure that the trade secret information is
2 maintained as secret.

3 MR. ROBINSON: And, Commissioner, access to
4 that information internally is protected as well.
5 So as Mr. Bowers mentioned, the employees that have
6 access to that information are on secured floors.
7 So over at the 241 building, the connector building
8 that sits to the side, our transmission planning
9 and our project management teams sit on the third
10 and second floor, and those are restricted. You
11 have to go through COOL compliance and a background
12 check to get access to those floors. Access to our
13 estimating system is also restricted.

14 So the team system that I mentioned, and how
15 we estimate those, has all this information in it.
16 You have to go through what we call COOL
17 compliance, which is our access program where
18 management approves your access and you have to
19 agree to certain terms to access that information.
20 And then other places where that information is
21 shared is restricted as well.

22 So our T&D counsel meeting that I've
23 mentioned before in testimony where we approve
24 these projects is restricted on attendance. And
25 the documents associated with these presentations

1 are also labeled as confidential.

2 COMMISSIONER JOHNSON: So you take your
3 non-disclosures very seriously?

4 MR. HEWITSON: Very seriously, Commissioner.

5 COMMISSIONER JOHNSON: Thank you.

6 MR. HEWITSON: And just to clarify for the
7 record, Mr. Robinson, the 241 building is 241 Ralph
8 McGill, which is Georgia Power headquarters; right?

9 MR. ROBINSON: That's correct.

10 MR. HEWITSON: Thank you.

11 COMMISSIONER PRIDEMORE: To the panel, if a
12 member of your staff or someone else in the company
13 violated the non-disclosure agreement or released
14 trade secret information, is that grounds for
15 expulsion?

16 MR. ROBINSON: It would be grounds for
17 discipline, up to and including termination, yes.

18 MR. HEWITSON: And, Mr. Robinson, just to
19 confirm, even employees of Georgia Power that are
20 allowed access to this transmission information,
21 much of it is called Critical Energy Infrastructure
22 Information, or CEII. They are required to go
23 through background checks as well; correct?

24 MR. ROBINSON: That is correct. Internally,
25 and that information is also protected with a

1 disclaimer that says that that information is
2 protected by law.

3 MR. HEWITSON: Thank you, Gentlemen.

4 CHAIRMAN SHAW: Mr. Robinson, I know a lot of
5 what y'all have talked about around the sensitive
6 information as far as it pertains to the
7 competitiveness, y'all have mainly spoke about
8 customer choice economic development projects, but
9 can you add or touch on a little bit about -- you
10 mentioned on the construction side, and obviously
11 there's -- as a result of this docket that we've
12 approved, there's a lot of growth in the system, so
13 obviously a lot of new construction. How would the
14 trade secret information affect that side of the
15 house, in terms of the construction side?

16 MR. ROBINSON: Yes, Chairman. As I mentioned
17 before, we go out and competitively bid our
18 transmission and substation work. So we have
19 internal crews, but we also have crews that we use
20 to manage ebbs and flows in our construction
21 business. So think of Quanta, think of Pike,
22 companies like that, as well as going out for
23 competitive bid or contracts for our major
24 equipment.

25 And so knowing this information -- and as I

1 mentioned before, the transmission project name
2 often has beginning points and end points in the
3 name, so Lawrenceville to Bethabara. And you
4 can -- you can use Google Maps to determine what an
5 approximate line mile would be for that. You could
6 back into the line mile cost of that project and
7 use that to influence your bid as it relates to
8 what we're planning the project for when you're
9 bidding into these RFPs. Same could be said for
10 material, equipment, transformers, and breakers.

11 CHAIRMAN SHAW: Yeah, and I know you're a
12 transmission guy; right?

13 MR. ROBINSON: Yes, sir.

14 CHAIRMAN SHAW: So you're mainly talking
15 about transmission, so -- and transmission is a
16 little different in terms of being a part of the
17 integrated system.

18 MR. ROBINSON: Yes.

19 CHAIRMAN SHAW: But what about on the
20 generation side, wouldn't that be probably even a
21 bigger deal?

22 MR. HUBBERT: Certainly -- Commissioner, it
23 certainly could be. Very similar to the
24 transmission side, we're working with various
25 original equipment manufacturers and engineering

1 procurement construction firms. So having that
2 information disclosed publicly could put us --
3 could harm -- potentially harm customers in those
4 conversations with all those providers.

5 MR. BOWERS: And I would add, we sign NDAs
6 with those vendors and those suppliers as well. So
7 if we disclose their cost information, we would be
8 in violation of those NDAs.

9 CHAIRMAN SHAW: Any other questions?

10 (No response.)

11 CHAIRMAN SHAW: All right. Ms. Whitfield,
12 did y'all have any cross?

13 MS. WHITFIELD: We do, and I don't want to be
14 misleading by saying just a little.

15 Mr. Sherrier -- we have a lot of exhibits, so
16 Mr. Sherrier -- we prepared a binder for you to
17 make it a little easier. And then we have some
18 handouts as well. So if Mr. Sherrier could
19 approach and hand those out --

20 CHAIRMAN SHAW: Go ahead.

21 MS. WHITFIELD: -- I would appreciate it.
22 And just some context for the binder, just as a
23 housekeeping matter as he's handing these out, what
24 you'll see in it -- the first tab is GIPL's
25 motion -- GIPL and Southface's motion.

1 The second tab is Georgia Power's response,
2 so you have them both there right in front of you.
3 And then after that are a number of exhibits that
4 we filed with our motion, as well as a few others
5 interspersed throughout that we'll refer to.

6 In addition, each binder has in the folder,
7 the red folder, a trade secret version of each
8 exhibit that we have asked disclosure of. And so
9 those will also be marked as the respective number
10 and indicated as trade secret for the record.
11 However, we don't need to, nor do we intend to talk
12 about the trade secret numbers or information. We
13 just wanted to make sure that the -- that you --
14 all Commissioners had it, in case you wanted to
15 look at it.

16 CHAIRMAN SHAW: Ms. Whitfield, the pulp and
17 paper industry thanks you once again.

18 MS. WHITFIELD: I'm trying to support the
19 forestry industry. I'm here for them in this
20 docket.

21 And I'll start by talking about 2A, which is
22 the revenue requirement exhibit. So, Mr. Hubbert,
23 it sounds like that's you.

24 CROSS-EXAMINATION
25

1 BY MS. WHITFIELD:

2 Q. First off, I want to talk about what this
3 information actually is, because when you were answering
4 questions, you answered questions that suggested that this
5 information includes detailed modeling information. Could
6 you describe what these columns are on the first page of
7 GIPL/Southface Exhibit 2A?

8 A. (Witness Hubbert) So on the first page, just
9 to make sure --

10 Q. That's it.

11 A. (Witness Hubbert) Okay. Yeah. So the first
12 page shows, starting from left to right, the case number,
13 which is an indicator or a reference number for the
14 different scenarios that were evaluated. So then the
15 second column shows each of the 13 different scenarios
16 that were evaluated in the IRP.

17 Then the next four columns actually show some
18 of the analytical results of the analysis that was
19 conducted. So the next column shows the real levelized
20 cents per kilowatt hour for each one of those scenarios,
21 which is a trade secret value.

22 Q. Which is redacted; correct?

23 A. (Witness Hubbert) This is redacted. The next
24 column shows for each of those scenarios, the percent
25 increase or decrease above the base case, which in this

1 case, the base case was the 111 with moderate gas and
2 lower carbon assumption. In the next column, it shows the
3 levelized cents per kilowatt hour, which is also a trade
4 secret redacted from the public disclosure version. And
5 then the last column shows the percent above base case
6 using that data point as well.

7 Q. The best you can, what does the real
8 levelized cents per kilowatt hour represent in plain
9 English? Why do you provide it? Why is it useful?

10 A. (Witness Hubbert) So rates are expressed in
11 cents-per-kilowatt hour. So it does as good a job as it
12 can with the data that it has to try to represent a
13 relative rate impact -- not a specific rate impact, but a
14 relative rate impact for the different scenarios that are
15 evaluated.

16 So, for example, if you had a -- the base
17 case, and then add to the base case a higher gas price as
18 opposed to a moderate gas price, what is the relative
19 impact or rate impact to customers? It's not used for
20 specific ratemaking. It's just to give relative guidance
21 on these scenarios.

22 Q. Why isn't it used for specific rate making?

23 A. (Witness Hubbert) Well, I'm not a rate
24 expert, so you would have to ask someone else on what's
25 used for the specific ratemaking for Georgia Power.

1 Q. Might it be because it's an estimate at this
2 stage in an IRP?

3 A. (Witness Hubbert) Yes. A lot of this is an
4 estimate at this stage of the IRP.

5 Q. In addition, this exhibit reflects the
6 incremental costs to pay for the requests made in this
7 specific IRP; correct?

8 A. (Witness Hubbert) Could you be more specific
9 on your question there?

10 Q. Sure. This exhibit is reflecting the rate
11 impact of the requests in the 2025 IRP, if they were all
12 approved and went forward; correct?

13 A. (Witness Hubbert) This is actually not. So
14 the things that Georgia Power requested in this IRP, for
15 example, the unit uprates at McIntosh, the nuclear
16 uprates, those were not embedded as an assumption in this
17 analysis. So this would not represent the relative rate
18 impact of those decisions.

19 Q. So which decisions are embedded in this
20 analysis?

21 A. (Witness Hubbert) So all of the existing
22 assumptions for the company's existing fleet. And then
23 for each one of these scenarios, the future generation
24 technologies that were selected as part of the expansion
25 plans for each one of these different scenarios would be

1 represented in this analysis.

2 A. (Witness Bowers) And I would add that the
3 extension -- the specific extensions of Plant Scherer
4 Unit 3 and Plant Gaston Units 1 through 4 and Unit A are
5 also represented in the assumptions within those cases.

6 Q. So it sounds like most of the requests from
7 the 2025 IRP are reflected here?

8 A. (Witness Hubbert) Some of the requests are.

9 Q. Okay. Would you describe this as an
10 incremental reflection of the levelized cost of those
11 assets that are included?

12 A. (Witness Hubbert) Yes, I think you could
13 describe it that way.

14 Q. And it compares -- to create this levelized
15 cents per kilowatt hour, you're relying on revenue
16 requirements; correct?

17 A. (Witness Hubbert) That is one of the data
18 points. That is correct.

19 Q. And in addition, if you flip the page to the
20 next page of GIPL/Southface Exhibit 2A, it shows some of
21 the information that's used to calculate that information
22 on the original table; correct?

23 A. (Witness Hubbert) That is correct.

24 Q. And that includes total annual revenue
25 requirements; correct?

1 A. (Witness Hubbert) It does include total
2 annual revenue requirements.

3 Q. Total annual gigawatt hours?

4 A. (Witness Hubbert) Yes.

5 Q. Nominal average cents per kilowatt hour, and
6 levelized revenue requirements, among a few other columns
7 there; correct?

8 A. (Witness Hubbert) That is correct.

9 Q. So this information here is designed to
10 reflect the annual revenue requirement of the assets -- of
11 some of the assets that are being requested by Georgia
12 Power in this IRP; correct?

13 A. (Witness Hubbert) It would cover -- yes, it
14 would cover the ones that Mr. Bowers just spoke of, among
15 other things. So it also includes the operating costs or
16 the variable costs for the existing fleet, as well as the
17 fixed costs or capital costs and operating costs of the
18 generic resources that were selected in each one of these
19 scenarios.

20 Q. But this isn't covering -- my understanding
21 is that this is just incremental and that it's not
22 covering the full base rate?

23 A. (Witness Hubbert) No, it covers -- it covers
24 the full -- it covers the operating costs, not the fixed
25 costs of existing resources. It covers the operating

1 costs or variable costs of existing resources, plus the
2 capital costs or fixed costs and operating costs of
3 generic resources that were added.

4 Q. Okay. So in addition to all the things you
5 just mentioned, does it also include things like fuel?

6 A. (Witness Hubbert) Yes.

7 Q. Would it also include things like emissions
8 costs for the generation units in question?

9 A. (Witness Hubbert) Yes.

10 Q. Would it also include things like the
11 environmental capital impacts?

12 A. (Witness Hubbert) To the extent they impact
13 the -- it does include that for the future generic
14 resources that are added. That is correct.

15 Q. And as we've already discussed, it includes a
16 number of different kinds of requests from Georgia Power,
17 included in this IRP, not all of them --

18 A. (Witness Hubbert) Not all.

19 Q. -- but a number of different kinds; correct?

20 A. (Witness Hubbert) It does.

21 Q. And that includes gas requests related to
22 uprates?

23 A. (Witness Hubbert) That was the one that I
24 mentioned is not included.

25 Q. That's the one that's excluded? Okay.

1 A. (Witness Hubbert) So as Mr. Bower said, so
2 the unit extensions, so the unit extensions are included
3 in the analysis. But the unit uprates at McIntosh, the
4 gas uprates, the nuclear uprates, they're not included.

5 Q. Okay.

6 A. (Witness Bowers) As well as, I would add,
7 hydromodernization costs are not included in this
8 estimate, you know.

9 Q. Okay. So this includes the -- there's a lot
10 not included in there. I'm not sure I appreciated that
11 until just now.

12 A. (Witness Hubbert) Yeah. Again, it's
13 provided, one, because the rules require us to do a
14 financial review assessment across these scenarios. But
15 it's provided to define a relative rate impact. So the
16 base assumptions are the same across every scenario. But
17 it's capturing, like, the gas price difference, the carbon
18 price difference, all those other differences, it's
19 capturing -- trying to single those things out to provide
20 a relative difference.

21 Q. Great. That's very helpful. Thank you.

22 So I want to look at some similar information
23 that Georgia Power has disclosed. And if Mr. Sherrier
24 could approach again with a handful of documents to
25 supplement the binder, we'll start with -- on the top of

1 each one of these folders is a chart. The charts will all
2 be -- they're tables, rather. They'll all be introduced
3 into evidence as a single exhibit of tables. But each
4 folder also includes a handful of exhibits.

5 And I'd like to start by looking at
6 Exhibit 22.

7 A. (Witness Bowers) I'm sorry. Could you point
8 us to which is Exhibit 22? Okay. I think we've -- I
9 think we've found it.

10 Q. It's this one.

11 A. (Witness Bowers) Got it.

12 (The documents referred to were premarked for
13 identification as GIPL/Southface Exhibit 22.)

14 Q. Do you recognize this exhibit?

15 A. (Witness Bowers) I do recognize this exhibit.

16 Q. Is this an estimated net impacts to customers
17 from the 2023 IRP update?

18 A. (Witness Bowers) Yes. This is -- this is a
19 data request response related to estimated net impact to
20 customers from the 2023 IRP update.

21 Q. And in this data request response as part of
22 the IRP update, are you providing information about the
23 estimated incremental revenue requirement due to load
24 growth here?

25 A. (Witness Bowers) Yes, we do.

1 Q. And you include an incremental view of total
2 revenues here?

3 A. (Witness Bowers) Yes. We estimate
4 incremental revenue due to load growth, specific to the
5 large loads that are in the 2023 IRP update.

6 Q. And you're also including here net estimated
7 incremental impact to customers; correct?

8 A. (Witness Bowers) That's correct.

9 Q. And estimated rate impact as a percentage;
10 correct?

11 A. (Witness Bowers) That is correct.

12 Q. And as you can see, this document at the top
13 says "public disclosure." These are all publicly
14 disclosed.

15 A. (Witness Bowers) That's correct. I would add
16 that because this was in the 2023 IRP update, and this was
17 between cycles for the company, this is not a triennial
18 IRP filing that is normally followed by a rate case that
19 this Commission hears.

20 We endeavored to provide as much information
21 as we could specific to the incremental resources that we
22 requested in the 2023 IRP update and the incremental load
23 growth specific to that IRP update to explain and justify
24 the requests in the '23 IRP update. Because it was -- it
25 was such an unprecedented time where load growth increased

1 tremendously and it advanced our capacity need a full
2 three years from winter of '28-'29 to the winter of
3 '25-'26.

4 Q. And you'll recall, of course, that at the
5 time of the conclusion of the 2023 IRP update, there were
6 projects included in that request that still required work
7 to be done, still required contract and/or bidding to be
8 done; correct?

9 A. (Witness Bowers) That's correct. We proposed
10 projects such as the combustion turbines at Plant Yates,
11 Units 8 through 10. We proposed company-owned battery
12 energy storage systems up to 1000 megawatts. Received
13 approval of 500 megawatts. So, yes, we included cost
14 estimates for those projects that we marked as trade
15 secret in that proceeding.

16 (The documents referred to were premarked for
17 identification as GIPL/Southface Exhibit 20.)

18 Q. I'd also like you to turn to your binder,
19 GIPL Exhibit 20. It's in the binder because it was
20 included with our original motion. In GIPL Exhibit 20,
21 this is a response to a request from staff about the total
22 revenue requirements over the 12-year planning horizon for
23 each of the four DSM cases in this 2025 IRP. Do you see
24 that?

25 A. (Witness Hubbert) Yes, we see it.

1 Q. And in that response, you provided the
2 present value, total revenue requirements for each one of
3 the proposed cases for two different scenarios; correct?

4 A. (Witness Hubbert) That is correct.

5 Q. And this is a public document; correct?

6 A. (Witness Hubbert) That is correct.

7 (The documents referred to were premarked for
8 identification as GIPL/Southface Exhibit 21.)

9 Q. Let's look at Exhibit 21.

10 A. Can I -- can I add something to this real
11 quick?

12 Q. Sure.

13 A. (Witness Hubbert) This is not different from
14 what we've done, even on the capacity expansion plans.
15 This is an aggregated value, the system level. It's a
16 present value over a defined period. In the filing itself
17 of the capacity expansion plans, we actually provided that
18 level of detail. It's a very high level. It's a
19 20-year-net-present value of the revenue requirements for
20 each expansion plan in the capacity expansion plans
21 document that was filed and publicly available. So it's
22 different when you're doing year-over-year annual values
23 versus a 20 -- 10-, 20-year present value that's
24 aggregated up.

25 A. (Witness Bowers) And I would like to add, for

1 the record, for the last exhibit, 22, it was similar in
2 that we provided aggregated cost information and redacted
3 specifically the proposed resource costs.

4 Q. Thank you. So let's take a look at
5 GIPL/Southface 21, which is marked at the top STF-BAI-1-1,
6 Attachment Panel A. And you'll recognize this document as
7 a document that is similar to documents that are produced
8 routinely in rate cases, and it provides information about
9 a number of financial pieces of information, but including
10 revenue requirement driver information; correct?

11 A. (Witness Bowers) Excuse me, counsel, which --
12 which docket is this exhibit from?

13 Q. This is from the 2022 rate case.

14 A. (Witness Bowers) Okay. Thank you. Could you
15 repeat your question?

16 Q. Yeah. I was noting that this is a document
17 that is similar to those found in the rate cases, and that
18 it provides detailed financial information. This specific
19 document on page 3, for example, includes a detailed
20 breakdown of revenue requirement drivers and the projected
21 financial cost for those in the projected years ahead of
22 2023, 2024, and 2025. Do you see that?

23 A. I see that, yes. I'd just note that we're
24 IRP witnesses and not as familiar with the rate case
25 materials.

1 Q. Does it surprise you --

2 A. (Witness Robinson) I am a rate case witness,
3 so... But thank you.

4 Q. Do you want to talk about it?

5 A. (Witness Robinson) Not my T&D.

6 Q. Does it surprise you that Georgia Power
7 provides this level of detail in its rate cases about the
8 specific drivers of its revenue requirements for projected
9 years 2023, 2024, and 2025?

10 A. (Witness Robinson) No, it does not. This
11 is -- it's not comparable to the information that we're
12 talking about, particularly the T&D. What is in this and
13 in this bar graph that you've got is the revenue
14 requirement for the incremental costs for T&D reliability
15 and resilience. For that category specifically, there's
16 many more things that go into that category than just the
17 ten-year plan items. It could be reliability, capital
18 maintenance, could be commitments like DOT relocations,
19 could be NERC requirements. So there's many other things
20 that go in that bucket. So it does not surprise me that
21 we disclosed that. But you cannot get to the same
22 information that I've mentioned before by just that
23 number.

24 Q. We'll get to transmission, I promise. Right
25 now, I just want to focus on the revenue requirement

1 piece. So knowing that this was disclosed in 2022, has
2 Georgia Power suffered economic harm as a result of this
3 disclosure?

4 A. (Witness Bowers) I'm not aware that we have.

5 A. (Witness Robinson) It has rights to the T&D
6 items. The economic harm that I spoke to before cannot be
7 calculated or deduced from this information that you have
8 in this exhibit.

9 Q. Mr. Robinson, can the T&D items be calculated
10 from Exhibit 2A? The revenue requirement and levelized
11 price of the plan?

12 A. (Witness Hubbert) Are we back to the
13 financial review document?

14 Q. We're still there.

15 A. (Witness Hubbert) That revenue requirement
16 does not include transmission costs.

17 Q. Thank you.

18 A. (Witness Robinson) And there's no
19 transmission costs.

20 Q. So would it surprise you -- or to put another
21 way -- let's back up.

22 Our customers paying higher prices as a
23 result of the disclosure of this information?

24 A. (Witness Bowers) I'm not aware that customers
25 are paying higher prices as a result of the disclosure of

1 rate case information.

2 A. (Witness Robinson) This information went into
3 the rate case, so it was used as evidence in the rate case
4 for the rate case proceeding, and the rates that went into
5 effect after the '22 rate case.

6 A. (Witness Hubbert) And I'd like to add the
7 annual revenue requirements, while it may not have caused
8 economic harm yet, it has the potential to do so for the
9 reasons that we've been talking about. Disclosing the
10 annual revenue requirements information, along with other
11 information that we're already disclosing -- I would
12 submit to you that Georgia Power is sharing a lot more
13 information publicly now than what we have in prior IRPs,
14 trying to be more transparent.

15 And one of those things is the expansion
16 plans on an annual basis. We have always provided
17 expansion plans aggregated up at a -- kind of over a
18 20-year period. But in this IRP, we've provided annual
19 expansion plans. So you can see each year what resource
20 is being selected. So someone -- Ms. Whitfield, you
21 acknowledged during the proceedings that Aurora modeling
22 is very sophisticated, complex. So the people that are
23 using this information are pretty savvy at what they're
24 doing.

25 They can use this information, along with

1 other information, like the expansion plans, to single out
2 a year where a single resource is being selected. So
3 let's just say, for example, a year where a combined cycle
4 is the only resource selected. They can look at the
5 difference in annual revenue requirements, see that it's a
6 combined cycle that's selected, and really back into the
7 cost that we project as the cost for a combined cycle.
8 That information could harm Georgia customers if a bidder
9 has that information, even if they raise their price \$1,
10 that's \$1 more Georgia customers would pay than they would
11 otherwise.

12 Q. So I have seen Aurora now.

13 A. (Witness Hubbert) Say it again.

14 Q. I have seen Aurora now and understand it
15 better.

16 A. (Witness Hubbert) You still think it's
17 sophisticated and complex?

18 Q. I still think it's sophisticated and complex,
19 and it's so sophisticated and so complex that I am curious
20 how you explain how it would be possible for a contractor
21 to help extend one of the facilities to use the total
22 revenue requirement that includes all the O&M, that
23 includes the current -- the current O&M resources and
24 newly added resources; that includes some assets that are
25 clear and some assets that are less clear to the public,

1 like myself; that includes different kinds of generation
2 resources; that includes cost assumptions; that includes
3 environmental cost impacts that may or may not apply to
4 that generator -- how does that developer and/or
5 competitor use that information from that total top-line
6 revenue requirement, how do they reverse engineer that?
7 Because that seems to be your --

8 A. (Witness Hubbert) Certainly, that is a
9 concern --

10 Q. -- concern.

11 A. (Witness Hubbert) -- that the company has.
12 So it's kind of like what I just shared. With -- if you
13 combine this information with other information that is
14 publicly available. So one thing I'll mention is, there
15 are a number of energy administration -- Energy
16 Information Administration reports that are required to be
17 submitted.

18 So any anybody has access to Georgia Power
19 and the sister operating company's unit, existing unit
20 information, with operating characteristics, for existing
21 information. So they can use that to calculate what the
22 annual revenue requirements, or operating costs, variable
23 costs, are for the existing fleet.

24 So then what's left is the generic fleet.
25 Again, if you combine that with the generic expansion plan

1 that is public, if there's a year where there's a single
2 resource selected, you then know what the fixed and
3 variable cost for that resource is. So there is a
4 potential, sharing this information, that a savvy bidder
5 or competitor could use that information to influence
6 their price.

7 Q. Do you believe that that potential is likely
8 based on your experience so far, as an employee of Georgia
9 Power?

10 A. (Witness Hubbert) I would say during --
11 because there's RFP rules and a number of RFPs that we
12 conduct as a company, there are some very, very savvy
13 bidders out there that that live in this world and do
14 detailed market intelligence. I think there is the
15 potential, yes.

16 Q. So you also mentioned that you were concerned
17 about the rate impact that this could have on your direct
18 testimony. And specifically, you mentioned how you were
19 concerned that large load sophisticated customers might
20 use, somehow, this high-level collated data point to
21 increase their position when negotiating their
22 contracts -- their price contracts with Georgia Power;
23 correct?

24 A. (Witness Hubbert) Mr. Bowers?

25 A. (Witness Bowers) Yes. Could you restate

1 that?

2 Q. During your direct testimony, you indicated
3 that this information could cause harm to Georgia Power
4 because of the way a large load customer could use it in
5 negotiations with Georgia Power when trying to establish
6 its price.

7 A. (Witness Bowers) Which information are you
8 referring to specifically?

9 Q. I'm referring to your testimony about
10 Exhibit 2A, the revenue requirements. We're still on
11 revenue requirements.

12 A. (Witness Hubbert) Okay. I'll speak to a
13 portion of it, then Mr. Bowers can add to it if he finds
14 it necessary to do so. Where I was coming from was with
15 the relative cents per kilowatt hour, it wasn't
16 necessarily the customer itself that could use it, it's
17 other competitors.

18 So the ones that Mr. Robinson spoke of within
19 the state of Georgia, the ones that Mr. Bowers spoke of
20 within the state of Georgia, but also outside of the state
21 of Georgia. If they have that information, it could give
22 them an advantage over Georgia and limit growth --
23 economic growth in the state of Georgia.

24 Q. When you say "other competitors," give us a
25 give us an idea of who you're referring to.

1 A. So, for example, the state of South Carolina,
2 a neighboring state to the east, could be competing for
3 the same large load customer.

4 A. (Witness Robinson) And we often do.

5 Q. Okay.

6 A. (Witness Robinson) And I mentioned the
7 transmission component of that. And if you calculate into
8 marginal cost of transmission, that is an input that goes
9 into our minimum bill calculation. And if you know that
10 number for generation, those are two main components of
11 minimum bill. And certainly, a customer could compare our
12 cost minimum bill to a cost in another area and use that
13 as a competitive advantage.

14 A. (Witness Bowers) And I would just add, so
15 we've established that we compete for load within the
16 state of Georgia and with other states. But also, on the
17 generation side, and Mr. Hubbert has alluded to this, but
18 we compete in RFPs against independent power producers.
19 So some examples within the states would be -- within the
20 state of Georgia would be independent power producers that
21 own assets like Walton County CTs; Monroe Power CTs;
22 Washington County CTs; Mid-Georgia Cogen; Tenaska; Exelon;
23 Heard combustion turbines. We compete with independent
24 power producers in those RFPs where we've put forth
25 company-owned proposals with a certain price, it gets

1 ranked and evaluated against any existing assets within
2 the state that are also bid into those capacity RFPs.

3 And then in terms of new builds -- so those
4 are just existing assets. In terms of new builds, we also
5 compete there whether it's gas or battery energy storage
6 systems or solar. And we're competing against entities
7 such as NextEra Energy Resources and other solar and
8 storage developers.

9 Q. One quick clarifying question. I think I may
10 have misunderstood you. But, Mr. Robinson, did you just
11 say that large load customers can identify Georgia Power's
12 minimum bill from the annual revenue requirements for its
13 2025 IRP plan?

14 A. (Witness Robinson) No, I was talking about
15 the transmission costs, and that calculation into marginal
16 cost of transmission, which is a component. And so you
17 could use that as a comparison across the nation as it
18 relates to those elements.

19 Q. Understood. Okay. I'd like to take a look
20 at the Table 2 that was included with your folder. And
21 this was compiled by counsel for GIPL and Southface. Are
22 you aware that revealing revenue requirements is common
23 practice in other utilities' IRP?

24 A. (Witness Hubbert) Can you -- can you let me
25 know or let us know, are these aggregated present value

1 revenue requirements or are these annual revenue
2 requirements? Because as I mentioned earlier, we provided
3 publicly aggregated present value revenue requirements in
4 this IRP.

5 Q. Let's take a look.

6 A. (Witness Hubbert) These appear to be
7 aggregated values over some period of time, which is
8 consistent with what we've provided in this IRP.

9 A. (Witness Bowers) And specifically, it's in
10 Technical Appendix, Volume 2, the resource mix study.

11 A. (Witness Hubbert) What we provided is in the
12 resource mix study.

13 Q. Okay. So no objection, then, that providing
14 the net present value revenue requirements for all of your
15 scenarios should be public?

16 A. (Witness Hubbert) Yeah, I would submit to
17 you, we've already provided that publicly. And so I think
18 this exhibit is actually misleading. It has the company's
19 IRP information blacked out. We actually provided that.
20 So if you were to take that out, it would show us being
21 consistent with other companies out there with this level
22 of detail of information.

23 Q. Well, I appreciate you clarifying that. And
24 if that's, in fact, the case, then I agree with you that
25 this is misleading, because it would suggest that you're

1 not disclosing something that you are. So I'll move on.

2 All right. Let's go to large loads. 3A, if
3 you could. I believe, Mr. Bowers, you testified about
4 this one in direct.

5 A. (Witness Bowers) That's correct.

6 Q. And you said a lot of things about the
7 modeling that goes into identifying how much large loads
8 will be required on the system, but are you clear that
9 GIPL and Southface are only asking for the information on
10 this exhibit, GIPL/Southface Exhibit 3A, in Table 7.2.1?

11 A. Yes. Yes, I understand that the information
12 marked as trade secret in Table 7.2.1 is what's being
13 requested to be disclosed to the public. That information
14 contains our risk adjusted loads for large load customers
15 in our pipeline, existing and committed -- existing and
16 potential customers.

17 This information, if disclosed, because we've
18 already disclosed the announced load associated with the
19 large loads in our pipeline, it could be used by
20 competitors to calculate the risk adjustment that Georgia
21 Power performs to translate the announced loads that we
22 get from each customer, or potential customer, to the risk
23 adjusted load that we're showing here.

24 For example, that would be a percentage. If
25 they divided these values by the announced load, they get

1 a percentage. That percentage would reflect how we risk
2 adjust the large loads. It gives competitors better
3 insight into how to plan in similar ways as Georgia Power
4 for large loads, and that could improve their pricing
5 offers and erode our competitive position for customer
6 choice loads.

7 Q. I would -- do you agree that most information
8 that Georgia Power provides here about how it works with
9 large loads provides companies better insight into how
10 Georgia Power works with large loads?

11 A. (Witness Bowers) I think we provide a high
12 level methodology, but we do not disclose the specific
13 inputs and assumptions that are within our load
14 realization model. For example, the probabilities that a
15 customer -- or a large -- potential customer would select
16 the state, select Georgia, that its load will materialize,
17 and how much of a delay we expect from that load.

18 Q. From Table 7.2.1, could a customer identify
19 P1 of the large load realization model?

20 A. (Witness Bowers) Not from this information
21 alone, no.

22 Q. Could they identify P2?

23 A. (Witness Bowers) They could not identify P1,
24 P2, or other inputs in the load realization model;
25 however, they could back into the total risk adjustment,

1 which is what we're trying to protect here, Commissioners.
2 Because in effect, let's say -- I don't know the specifics
3 of how our competitors operate, because they're not
4 required to disclose their process, their methodology.
5 But if they were to adopt this risk adjustment that
6 Georgia Power is using, it could lead a competitor to
7 pursue a large load that they might have otherwise thought
8 they couldn't pursue. That erodes our competitive
9 position. That is harmful -- potentially harmful to our
10 customers.

11 Q. So we agree that this is a number that simply
12 reflects the output from that large load realization
13 model.

14 A. (Witness Bowers) That's correct.

15 Q. And it does not reflect, nor could one
16 reverse engineer the materialization assumptions that go
17 into that model?

18 A. (Witness Bowers) They could -- they could
19 calculate an aggregate percentage of those various inputs.

20 Q. And the aggregate percentage isn't part of
21 that model; correct?

22 A. (Witness Bowers) It is the model. This is a
23 proprietary model that Georgia Power has developed that we
24 believe gives us a competitive advantage to translate that
25 announced load that we get from customers to this risk

1 adjusted load.

2 Q. It's the output; correct? Of the model?

3 A. (Witness Bowers) This is the output of that
4 proprietary model, yes.

5 Q. Okay. And other than the percentage of the
6 total announced load in the pipeline -- which I agree this
7 would reflect -- other than that one piece of information,
8 the other assumptions that -- all of the assumptions that
9 go into the large load realization model cannot be parsed
10 out from this number; correct?

11 A. (Witness Bowers) They can't. But the one
12 piece that we're trying to protect here, why would we
13 disclose this and erode Georgia Power's competitive
14 position and potentially harm our customers?

15 Q. All right. I would like you to take a look
16 at Table 3.

17 A. (Witness Bowers) Is that in the green folder?

18 Q. If Mr. Sherrier can approach?

19 No, you're about to get it.

20 You understand that a lot of other utilities,
21 of course, are going through the same shift with large
22 load customers and figuring out the best way to move
23 forward with incorporating large load customers into their
24 grid; correct?

25 A. (Witness Bowers) Yes. I'm aware that other

1 utilities are in a similar position as us.

2 Q. And are you also aware that other utilities
3 are disclosing, as part of their IRP, how much of that
4 load they expect to need to plan for?

5 A. (Witness Bowers) I'm not aware of how much
6 they disclose large load projections.

7 (The documents referred to were premarked for
8 identification as GIPL/Southface Exhibit 3D.)

9 Q. Let's take a look at Exhibit 3D in your
10 binder.

11 MS. WHITFIELD: And for these exhibits,
12 Commissioners and panel, the first page -- because
13 there's so many. The first page is just a snippet
14 of the key information to make it a little easier,
15 but the supporting full pages are immediately
16 behind those.

17 BY MS. WHITFIELD:

18 Q. So the first page is an excerpt. The
19 immediate pages from which they were pulled is -- are
20 immediately behind them as part of the exhibit. And of
21 course, we did not include the full IRP for anyone -- or
22 most of the full documents, rather just the relevant
23 pages. So for this one, you see here, Santee Cooper's
24 projected winter peak demand. Do you see that?

25 A. (Witness Bowers) I see that.

1 Q. And do you see that they also are providing a
2 range of projected potential new large loads as part of
3 that peak?

4 A. (Witness Bowers) I see that it appears to be
5 a probability distribution of their large loads.

6 Q. Okay. All right. If we could turn to
7 Exhibit 3.

8 A. (Witness Bowers) I will note that Figure 3 --
9 yeah, Georgia Power also provides aggregate winter peak
10 demand in its IRP publicly.

11 Q. Sure. Yes, but not for large loads?

12 A. (Witness Bowers) Not for the specific large
13 load stuff.

14 Q. Right. What is it that's different about
15 providing the full winter peak needs and customers
16 evaluating your resource potential versus the peak that
17 you're expecting? You do provide that. What is unique
18 about telling customers which sliver of that peak is
19 specifically large load?

20 A. (Witness Bowers) The specific portion of the
21 load forecast that we compete on is that related to large
22 loads. The rest is organic growth that is inherent within
23 our system.

24 (The documents referred to were premarked for
25 identification as GIPL/Southface Exhibit 3C.)

1 Q. All right. Let's take a look at 3C. This is
2 Dominion Virginia's IRP forecast.

3 A. (Witness Bowers) I'm sorry. Did --

4 Q. 3C in your binder?

5 A. (Witness Bowers) I see it, yes.

6 Q. And if you look at either the snippet at the
7 front or page 14 of the full pages. Do you see here that
8 they're providing customer contracted capacity versus
9 their expected metered coincident demand for large loads?

10 A. (Witness Bowers) Give me one moment.

11 Q. Sure.

12 A. (Witness Hubbert) I would just like to point
13 out that -- I kind of mentioned this earlier -- we
14 don't -- for these other utilities that do share this
15 information, we don't really know what their regulatory
16 requirements are, if they're required to disclose it by
17 the regulators or their state legislators. In this
18 particular case, Dominion Virginia is in PJM. PJM may
19 require that they disclose this.

20 So many -- I think a lot of those
21 considerations or factors are going to be at play here as
22 we go look at some of these other utilities and what's
23 really driving them to disclose this as it compares to
24 Georgia Power Company.

25 Q. Sure.

1 A. (Witness Bowers) And it does appear that
2 they're providing the contracted load associated with
3 electric service agreements with their large loads, as
4 well as the metered load appears to be aggregated for
5 their IRP forecast.

6 Q. All right.

7 COMMISSIONER PRIDEMORE: To your point, I
8 think it also impacts MISO, based upon the listing,
9 based upon those that are within the list. MISO
10 might require it in their territory as well.

11 MR. BOWERS: Right.

12 BY MS. WHITFIELD:

13 Q. Do you have any reason to believe, along that
14 line of argument -- do you have any reason to believe that
15 other utility commissions don't want to protect their
16 utilities from economic harm?

17 A. (Witness Robinson) Other utilities may be in
18 markets that are different than George Power's.

19 Q. Sure.

20 A. (Witness Robinson) We have customer choice
21 here in Georgia. We have an integrated transmission
22 system that doesn't exist anywhere else in the United
23 States. Many of these that you have examples of are in
24 different market structures that, as Mr. Hubbert said, may
25 require this type of disclosure. So I can't speak to the

1 specifics of those, but I can tell you that Georgia Power
2 is very different than many of these utilities that you've
3 listed here.

4 COMMISSIONER PRIDEMORE: Mr. Robinson gave
5 you a fair answer. I'm going to come back at you
6 with this.

7 MS. WHITFIELD: Yeah.

8 COMMISSIONER PRIDEMORE: That's an appalling
9 question. To ask a utility whether or not they
10 think other state utility commissions don't work in
11 the best interests of their customers, or protect
12 their utilities, or work with their utilities?
13 What if I asked you what your opinions are of other
14 intervenors that come before this Commission, do
15 you believe that they act in the best interest of
16 those that they represent in their intervenorship?
17 That's not a -- that's a completely preposterous
18 question to ask, Ms. Whitfield.

19 MS. WHITFIELD: I think --

20 COMMISSIONER PRIDEMORE: You're asking a
21 utility to analyze the work of another state
22 utility commission. They don't work in that state.
23 They don't -- they don't come before that
24 Commission.

25 MS. WHITFIELD: Well, that is certainly

1 information for this Commission to evaluate and
2 consider when evaluating all the facts before you.

3 COMMISSIONER PRIDEMORE: Evaluate your bad
4 questions, yeah.

5 (The documents referred to were premarked for
6 identification as GIPL/Southface Exhibit 3E.)

7 BY MS. WHITFIELD:

8 Q. All right. Let's take a look at Exhibit 3E.
9 This is Duke Carolina's resource plan, and then this one
10 we have Duke Energy Carolina and Duke Energy Progress.
11 And I believe this one is reflected in megawatt hours for
12 their large load forecast. Do you see that?

13 A. (Witness Bowers) I see it.

14 Q. And this is the adjustment that they are
15 using in their forecast attributable to large site
16 developments; correct?

17 A. (Witness Bowers) That is how it's labeled.

18 (The documents referred to were premarked for
19 identification as GIPL/Southface Exhibit 3F.)

20 Q. Okay. And let's take a look at Exhibit 3F.
21 This is -- this is Louisville Gas and Electric Company and
22 Kentucky Utilities. In this resource plan, they provide
23 their load scenario in megawatts. And for data centers,
24 they provide a low, mid, and high range. Do you see that?

25 A. (Witness Bowers) I see it.

1 Q. Okay.

2 A. (Witness Hubbert) Do you know in this case,
3 is this an announced load or a load that's actually in
4 their load forecast? Because that's different. Georgia
5 shares the announced load.

6 Q. Sure. These are load forecast scenarios.

7 A. (Witness Hubbert) Okay.

8 (The documents referred to were premarked for
9 identification as GIPL/Southface Exhibit 3G.)

10 Q. And then 3G, there's Indiana Michigan. And
11 these are forecasted loads for their large loads, which
12 they call hyperscalers. Do you see that? And these are
13 by megawatt as well.

14 A. (Witness Bowers) I see it.

15 Q. So what is it that makes Georgia particularly
16 vulnerable to revealing its forecast for large customers?

17 A. (Witness Bowers) I think I've explained our
18 competitive position here in the state of Georgia. We
19 compete against 42 EMCs, 51 municipalities, for customer
20 choice load 900kW and above. We compete for similar
21 projects as these utilities are competing for, for large
22 loads. We see potential economic harm to our customers
23 for disclosing that information. I can't speak to why or
24 the line of thinking behind these other jurisdictions'
25 either election or requirement to disclose large load

1 forecasts.

2 Q. Okay. Let's take a look at 4A. And my
3 understanding, please correct me if I'm wrong, but my
4 understanding is that Georgia Power's theory of how
5 revealing this information harms Georgia Power is because
6 a sophisticated customer could use this information and
7 back in to the information in the prior exhibit; is that
8 correct?

9 A. (Witness Bowers) That's fair. We think this
10 exhibit provides further specificity at the class level,
11 and a sophisticated competitor could use similar methods
12 to obtain the risk adjustment.

13 Q. But Georgia Power does publicly provide the
14 class-specific sales projections; correct? In its IRP?

15 A. (Witness Bowers) I'm not sure. Could you
16 point me to a reference?

17 Q. Well, that's fair. I don't know that I have
18 one in front of me. I thought that you guys would know
19 offhand. But I will represent to you that you do provide
20 class-specific sales information. Could you describe for
21 me what the difference is between sales information and
22 the class-coincident-demand information?

23 A. (Witness Bowers) I'm sorry, not without
24 seeing the specific sales information that we've
25 disclosed.

1 Q. Just generally. I don't mean with respect to
2 your disclosures. I mean just generally with respect to
3 coincident demand versus -- coincident-demand projections
4 by class versus sales projections by class.

5 A. (Witness Bowers) I'm sorry. I have to see
6 the information.

7 A. (Witness Robinson) And I don't think any of
8 the three of us can speak to that as an expert
9 perspective.

10 Q. Okay. All right. Let's go to 6A. 6A --

11 CHAIRMAN SHAW: Ms. Whitfield, remind me
12 again which sections you said y'all agreed to.

13 MS. WHITFIELD: Oh, yes, I should have -- I
14 should have started with that at the outset.

15 So Exhibit 5 dealt with the size and type of
16 loads that were available to serve Georgia Power,
17 but we expect that that will be provided in a
18 matter of weeks at this point, as part of the --

19 CHAIRMAN SHAW: Right.

20 MS. WHITFIELD: -- filing by Georgia Power in
21 its certification proceeding this fall -- or
22 summer. So Exhibit 5, we are not pursuing at this
23 time. And Exhibit 7 -- Exhibit 7 is with regard to
24 outage information, and Georgia Power has updated
25 that document with additional information

1 unredacted that meets our needs. So we don't --
2 we're not pursuing Exhibit 7.

3 CHAIRMAN SHAW: Five and seven.

4 MS. WHITFIELD: That's right.

5 CHAIRMAN SHAW: Thank you.

6 MS. WHITFIELD: All right. Where was I?

7 CHAIRMAN SHAW: Sorry about that.

8 MS. WHITFIELD: No. That's okay.

9 BY MS. WHITFIELD:

10 Q. 6A. So you were describing the information
11 in 6A. These are the overall costs and performance of
12 generic types of power production to evaluate the most
13 economically optimal resource mix for Georgia Power
14 customers; correct?

15 A. (Witness Hubbert) That is correct.

16 Q. Are these numbers used across Southern
17 Company or are they specific to Georgia Power?

18 A. (Witness Hubbert) These are system level
19 numbers used across the Southern Company retail operating
20 companies.

21 Q. Are they -- so they're used as well by
22 Alabama Power and Mississippi Power?

23 A. (Witness Hubbert) That is correct.

24 Q. Are Alabama Power and Mississippi Power
25 allowed to bid into RFPs conducted by Georgia Power?

1 A. (Witness Hubbert) I think that is a
2 possibility. I think they could have that. I think they
3 could bid into the RFP. I'm not an expert in that area,
4 but I think that is an option.

5 Q. Can you identify any procedures taken to
6 ensure that this information shared across the Southern
7 Company system isn't provided to individuals who are
8 involved in those bids?

9 A. (Witness Hubbert) Could you repeat your
10 question one more time, please?

11 Q. Yeah. Could you -- well, I can repeat a
12 similar question. Could you please identify any processes
13 that are in place to ensure that individuals at those
14 other operating companies who would bid in to Georgia
15 Power's RFPs do not have access to this system-wide
16 information?

17 A. (Witness Hubbert) So if that were to occur,
18 they haven't bid into any RFPs that Georgia has conducted
19 already. But it would be very similar to how Georgia
20 conducts its RFPs today. There's evaluation teams
21 established. There's company-owned proposal teams
22 established, and there's significant effort taken to
23 segregate those teams from one another and the information
24 available to those teams.

25 Q. And are generic -- is generic cost

1 information one of the things that's discussed when doing
2 that segregating?

3 A. (Witness Hubbert) I think it would have to be
4 one of the items discussed, if that were to occur.

5 Q. Okay. So you mentioned on your direct
6 testimony about this information. I don't recall the full
7 context. I was taking notes as you were writing, but you
8 used the phrase "site specific." I just want to be clear
9 that these estimates are not site specific; correct?

10 A. (Witness Hubbert) That is correct. Yeah. So
11 as I was speaking earlier, I think I did correct myself
12 and say region specific, not site specific.

13 Q. Okay. I just wanted to make sure I didn't --
14 didn't catch the second part. So these generic resources
15 and these estimates here lack specifics such as location
16 specifics, site specifics; correct?

17 A. (Witness Hubbert) That is correct.

18 Q. They lack defined specifics such as
19 transmission, interconnection, and deliverability
20 information; correct?

21 A. (Witness Hubbert) No, these actually do have
22 some amount of transmission interconnection costs.

23 Q. It's generic, though; right?

24 A. (Witness Hubbert) It is generic.

25 Q. And not specific to the project -- a

1 particular project?

2 A. (Witness Hubbert) That is correct. It's
3 using actual information, though, from actual projects and
4 kind of using that to inform the generic transmission
5 interconnection costs that goes into these values.

6 Q. Sure, sure, sure. The generic resources also
7 don't define the specifics of the land and fuel
8 availability information; correct?

9 A. (Witness Hubbert) That is correct.

10 Q. Or the finalized engineering plans or the
11 necessary environmental permits; correct?

12 A. (Witness Hubbert) That is correct.

13 Q. And you would agree, of course, that in RFP
14 processes, bidders are going to use that detailed site
15 specific information to inform their bids; right?

16 A. (Witness Hubbert) Yes. In addition to kind
17 of a starting point, which is kind of what's represented
18 here, is you've got a starting point, and then you look at
19 those site specific factors to inform your bid.

20 Q. Did any of you -- you did testify in the 2023
21 IRP docket; correct?

22 A. (Witness Hubbert) No, the '25 IRP was my
23 first.

24 Q. Oh, okay. Okay. All right. Let me skip
25 that then.

1 From this information here, can you point
2 me -- you also were talking about avoided energy costs on
3 your direct. Can you point me to the specific column or
4 specific information that concerns you with respect to
5 avoided energy costs on Exhibit 6A?

6 A. So it's not in 6A. It's actually in the IRP
7 document itself, where we talk about how the generic
8 expansion plans establish the existing fleet, plus the
9 future fleet.

10 Q. Right.

11 A. (Witness Hubbert) Once we have that level of
12 information, we can do a more detailed hourly production
13 cost analysis. And then derived from that are the
14 system's avoided energy costs. And those avoided energy
15 costs are used to determine the energy value for all
16 supply-side and demand-side decisions for the next -- for
17 the next -- until the next resource plan is developed.

18 Q. Okay. Thank you. All right. Let's take a
19 look at Table 6, and this table -- sorry -- if
20 Mr. Sherrier could approach.

21 CHAIRMAN SHAW: Sure.

22 BY MS. WHITFIELD:

23 Q. This table was not produced -- was not
24 compiled by counsel for GIPL and Southface. This table
25 was compiled as a staff exhibit to their testimony in this

1 docket. Are you familiar with this exhibit from staff
2 panel Newsome, Hayet, Sandonato, and Wellborn?

3 A. Yes.

4 Q. And based on the information in this exhibit
5 or based on your general knowledge, would you agree that
6 other states reveal the generic input information that's
7 been requested here?

8 A. (Witness Hubbert) Yes. This exhibit does
9 show values that other states and utilities -- and other
10 publicly available sources of information for this type of
11 event -- for this for the combustion turbine mentioned
12 here, so...

13 A. (Witness Bowers) So specifically, to add to
14 that, the footnote indicates that sources such as the
15 Energy Information Administration annual energy outlook is
16 used, which is publicly available information.

17 Q. Okay.

18 A. (Witness Hubbert) And that's what we were
19 speaking to earlier. And Mr. Bowers said this, why
20 they've elected to disclose this, or if they're required
21 to disclose this, we can't speak to. We don't know all
22 the rules and requirements in those -- for those companies
23 and for those jurisdictions. Many of these companies
24 actually do just simply use the publicly available
25 generation technology costs for their purposes.

1 We don't -- for the reasons I mentioned
2 earlier, we're making billions and billions of dollars of
3 decisions, so we're trying to use information that's
4 specific to our region. Our generation development folks
5 are the experts in this area, work directly with OEMs and
6 EPCs, and we're trying to get the best information
7 possible because of the magnitude and scale of the
8 decisions that we're making for the customers.

9 Q. Sure.

10 A. (Witness Bowers) And I would note that two
11 other sources listed here are also publicly available. So
12 the National Renewable Energy Lab 2024 ATB, as well as
13 Lazard's Levelized Cost of Energy 2024. Those are
14 publicly available costs. So some of these utilities
15 are -- or some of the columns shown here are publicly
16 available costs.

17 A. (Witness Hubbert) And just to add to that,
18 some of the utilities actually use the publicly available
19 costs, as I was just saying.

20 Q. Uh-huh. And your concern about revealing
21 this cost is that it would somehow skew prices from
22 bidders; correct?

23 A. (Witness Hubbert) Yeah. Our concern is that
24 with this information being there, a sophisticated bidder,
25 just doing their market intelligence, could use this

1 information combined with other information that's
2 available to get a sense of what's the company-owned --
3 company-owned proposal cost. So if they -- if they just
4 raise their price \$1, that hurts -- provides potential
5 harm to Georgia customers.

6 Q. Are you aware that other utilities, even in
7 Georgia, reveal much more specific costs for their
8 projects? Like Exhibit 26, which is in your folder, this
9 is a presentation from Oglethorpe Power, and if you skip
10 to line -- page 4.

11 A. (Witness Hubbert) Which exhibit is it?

12 Q. Yeah. It is Exhibit 26.

13 (The documents referred to were premarked for
14 identification as GIPL/Southface Exhibit 26.)

15 A. (Witness Hubbert) I am not familiar with
16 Oglethorpe's practices. Okay. I wouldn't be surprised,
17 though, with them being a non-regulated utility with
18 access to different financing opportunities, they may be
19 required to disclose that for those reasons. I really
20 can't speak to all that.

21 Q. Do you see here that they're disclosing
22 the -- a project that they are planning on, that they have
23 not yet finalized their budget, is the last bullet here?
24 Do you see that? "We anticipate finalizing our budget by
25 late summer, following the completion of our RFP process

1 for engineering, procurement, and construction services."

2 A. (Witness Hubbert) Yes, I see that mentioned
3 there now.

4 Q. And right above, they provide a preliminary
5 cost estimate for this facility as 1.8 to \$2.3 billion.
6 Do you see that?

7 A. (Witness Hubbert) I see that.

8 Q. And do you see right above that that they're
9 providing the specific equipment manufacturer that they
10 have chosen, as well as the model number for the turbines
11 and the generators that they're using?

12 A. (Witness Hubbert) I see that.

13 A. (Witness Bowers) I'd note that we don't know
14 if this project was selected as part of an RFP process
15 whereby multiple bidders would submit cost estimates for
16 projects. They may have been working with this supplier
17 directly and may have permission from this vendor, this
18 supplier, to disclose the cost.

19 Q. The cost here, 1.8 billion to 2.3 billion, is
20 a cost estimate for the facility, not for the turbines.
21 Do you see that in the document?

22 A. (Witness Hubbert) It does reference facility.

23 Q. All right. Let's, I think, move -- yes, to
24 Exhibit 8, transmission.

25 So, Mr. Robinson, you've already walked

1 through Exhibit 8A in some detail, explaining, as a
2 reminder, that it includes the project name, the team's
3 number, the need date, and then the estimated cost broken
4 down by Georgia Power, Georgia Transmission Company, MEAG,
5 DU --

6 A. (Witness Robinson) Dalton Utilities.

7 Q. Dalton Utilities, and then the total column
8 as well; correct?

9 A. (Witness Robinson) That's correct.

10 Q. And we've already established in this
11 proceeding that Georgia Power does not have any
12 competitors for transmission projects. Specifically,
13 though, you do contract out transmission projects as part
14 of the bidding process; correct?

15 A. (Witness Robinson) Could you repeat your
16 question? I didn't hear the first part of it.

17 Q. We've already established that Georgia Power
18 Company does not have any competitors for transmission
19 projects; correct?

20 A. (Witness Robinson) There are no third parties
21 independently building transmission projects in the state
22 of Georgia. That's correct.

23 Q. But you do contract out transmission work;
24 correct?

25 A. (Witness Robinson) We contract out

1 engineering -- engineering work, construction work, as
2 well as our material and equipment.

3 Q. And your theory of potential harm here is
4 that by revealing the overall price for the project,
5 contractors will see that and potentially increase their
6 bids; correct?

7 A. (Witness Robinson) It could influence and
8 give competitive advantage to those, yes.

9 Q. You're aware that contractors typically try
10 to price their bids to be competitive with other bidders?

11 A. (Witness Robinson) I am aware of that, that
12 would be good practice on their side. But having
13 knowledge as it relates to the cost per unit that we are
14 planning to or estimating to here in the state would give
15 a competitive advantage to those potential bidders.

16 And I can tell you that our costs are
17 different than other areas. I can't specify how different
18 they are, or how they are different, but they are
19 different. And having knowledge of those costs could give
20 a competitive advantage to someone bidding into our
21 processes.

22 Q. All right.

23 A. (Witness Robinson) Our RFPs.

24 Q. Let's take a look, if Ms. Sherrier could
25 approach, at a few additional documents. And while he's

1 handing those out, I'll ask you some questions about the
2 nature of these estimates in this document, document 8A.
3 These estimates, are they just that? Are they
4 estimates -- project estimates, when they're included at
5 this stage in the IRP?

6 A. (Witness Robinson) There is a scoping process
7 that we go through. We determine the -- what we call
8 planning grade estimates.

9 Q. Yep.

10 A. (Witness Robinson) And those processes are
11 detailed in our Technical Appendix, Volume 3, on how we go
12 through that process and approval. But there is a process
13 for our planning grade estimates and how those are
14 developed and used.

15 Q. And these estimates can be revised from year
16 to year, if the given scope of a project changes or a
17 significant input changes, like material cost; correct?

18 A. (Witness Robinson) They can, and you can see
19 that in our ten-year plans that we file annually, that we
20 do update costs, as we know. We go through our *gated
21 process and get closer to construction.

22 Q. And these total cost numbers for these
23 transmission projects include a lot of features of the
24 project, including cost of materials; potentially land, if
25 needed; engineering; permits; construction; labor;

1 correct?

2 A. (Witness Robinson) There are several factors
3 that go into, depending on the type of construction,
4 whether it's a line project or a substation project. But
5 there are different factors that go into that cost.

6 (The documents referred to were premarked for
7 identification as GIPL/Southface Exhibit 27.)

8 Q. Okay. Let's take a look in the folder at
9 GIPL/Southface Exhibit 27.

10 A. (Witness Robinson) But I will say to your
11 question, it doesn't take much to figure out what
12 percentage of a project would be land, what percentage of
13 a project would be line -- conductor costs, to
14 Commissioner Pridemore's question earlier, structure
15 costs, if you know that it's a 500kV project. It doesn't
16 take much to know how the breakdown of that project
17 generally would -- would be -- would happen, so...

18 Q. If you could, Mr. Robinson, take a look at
19 Exhibit 27. And again, like the others, this is not the
20 full report. This is excerpts from the documents. Do you
21 recognize this document?

22 A. (Witness Robinson) Yes.

23 Q. And this document is the designation study
24 report for the Yates CT Units; correct? Yates 8 through
25 9 -- through 10. Sorry.

1 A. (Witness Robinson) Yes, 8 through 10.

2 Q. Just high level, what's the purpose of this
3 kind of report?

4 A. (Witness Hubbert) So when the retail
5 operating companies make a resource decision, we have to
6 submit a request through the Open Access, Same Time
7 Information System, OASIS, to request a designation to be
8 able to designate that resource to serve the capacity and
9 energy needs of the Georgia customers. So that's
10 submitted to the transmission organization. They do
11 analyses of the request and determine a couple of things:
12 One, if service can be available by the time frame
13 requested; and also what is an estimated or potential cost
14 of transmission to make that capacity energy available to
15 serve Georgia customers in this case.

16 Q. And the estimated cost for the Yates project
17 specifically was publicly and regularly shared by Georgia
18 Power as part of the Commission proceeding. Do you recall
19 that, the top line \$60 million number?

20 A. (Witness Bowers) I recall that from the 2023
21 IRP update.

22 Q. Okay. And on page 6, which is really just
23 the back page of the exhibit for our purposes -- here, do
24 you see multiple lines and projects being described?
25 Including, for example, P5, which talks about the

1 beginning and the end of the line, the voltage of the
2 line, the jumpers that need to be replaced, how long the
3 line is? Do you see that?

4 A. (Witness Robinson) Yes.

5 Q. And then in the last column on that page, it
6 has the attributable cost in dollars?

7 A. (Witness Robinson) Yes. And it's also a GTC
8 project. And there's a footnote down below that says
9 that's based on Georgia Power's estimates, and actual
10 costs would need to be determined by GTC.

11 Q. Okay. So let's look at P7. Here we have a
12 line, beginning to end. The amount of the voltage
13 advanced by one year. The one and a half mile
14 230-kilovolt kilovolt reconductor from East Point to Union
15 City, and the specific cost of accelerating that by one
16 year is listed here in this document. Do you see that?

17 A. (Witness Robinson) Yes.

18 Q. And if you look at footnote six, the specific
19 total project cost is reflected in line 6. Do you see
20 that?

21 A. (Witness Robinson) Yes.

22 Q. And that pattern repeats itself for these
23 various projects on page 6; correct?

24 A. (Witness Robinson) That's correct.

25 Q. At the time of preparing these reports, these

1 projects are in the planning phase; correct?

2 A. (Witness Robinson) Not one that is being
3 advanced, that would probably be in engineering phase --

4 Q. That's fair.

5 A. (Witness Robinson) -- Or even closer to
6 construction than many.

7 Q. Would the rest of them be in planning phase?

8 A. (Witness Robinson) Yes.

9 (The documents referred to were premarked for
10 identification as GIPL/Southface Exhibit 29.)

11 Q. All right. Let's take a look at
12 GIPL/Southface Exhibit 29. And this is labeled on the
13 front Generator Interconnection System Impact Study, dated
14 April 12th, 2024. I want to ask you about page 15.

15 A. (Witness Robinson) Yes.

16 Q. On page 15, do you see that there is a very
17 detailed project description of a new substation? It
18 includes details like the dual line current differential
19 protection panel that will be needed. It includes details
20 like the three 230-kilovolt CC DTs. It includes details
21 like the kind of meter that needs to be installed at the
22 point of interconnection, and other details, as well as a
23 projected project completion time. Do you see that here?

24 A. (Witness Robinson) I do.

25 Q. As well as the cost estimates?

1 A. (Witness Hubbert) Yes.

2 Q. We can go through these others and other
3 pages, but would you agree that similar levels of detail
4 are provided in system impact studies like these when
5 produced by Southern Company?

6 A. (Witness Robinson) Those are costs for
7 projects associated with these OASIS studies. Those
8 disclosures are required by FERC. And then in the study
9 that Mr. Hubbert mentioned, as part of the process,
10 including those costs, what we're trying to protect is a
11 portfolio of projects that we have that show -- they run
12 the gamut from 115 to 230 to 500 to a 500 station to a 500
13 breaker cost. All of those being disclosed in a ten-year
14 plan, multiple years, year-after-year, I'd still argue
15 would give a competitive advantage to someone that would
16 have that cost, particularly as it relates to calculating
17 our marginal cost of transmission.

18 Q. None of the reports that we just reviewed are
19 marked trade secret; correct?

20 A. (Witness Robinson) No, because you probably
21 got these from OASIS.

22 Q. None of these reports are marked
23 confidential; correct?

24 A. (Witness Robinson) That is correct. And as I
25 mentioned before, these are reports that are required

1 under our open access transmission tariff, required by
2 FERC to be posted on OASIS.

3 Q. And it sounds like you're aware that these
4 reports are made publicly available by Southern Company by
5 request on the Oasis portal?

6 A. (Witness Robinson) Yes. And these are small
7 batches of projects. These do not include massive 500kV
8 projects that are in our ten-year plan or other large
9 projects. These are typically projects that are direct,
10 local costs related to these generation interconnection
11 studies that you mentioned, same as Yates. So the
12 magnitude of what we're talking about is totally
13 different.

14 (The documents referred to were premarked for
15 identification as GIPL/Southface Exhibit 32.)

16 Q. Let's take a look at GIPL/Southface
17 Exhibit 32.

18 A. (Witness Robinson) 32?

19 Q. Yes. Okay. I'll give you a minute to get
20 familiar with it. Do you recognize this kind of document?

21 A. (Witness Robinson) I am not familiar. This
22 is not a Georgia Power document.

23 Q. This is a document that was filed with USDA
24 detailing transmission impacts as part of its required
25 obligations. I suppose it was probably filed by Southern

1 Company, though, I don't know who would file it.

2 A. (Witness Robinson) No, it is not. So GTC,
3 the EMCs, have the ability to borrow money from the USDA
4 under the REA.

5 Q. Uh-huh.

6 A. (Witness Robinson) And my guess is this is a
7 requirement for access to those dollars, but this is not a
8 Georgia Power document.

9 Q. Okay. So you are aware that these are
10 Georgia Power lines; correct?

11 A. (Witness Robinson) Yeah, I believe these are
12 all GTC lines. So this is associated with a project
13 that's in East Georgia, a majority of the project is
14 assigned to GTC. There's a small portion of the project
15 that Georgia Power has, but it's further south in the
16 state and not in the Walton County area that this is
17 specifying. I believe these 230kV lines that are
18 specified here are all the responsibility of Georgia
19 Transmission Corporation.

20 Q. Okay. So let's take a look at some of the
21 information Georgia Transmission Corporation is providing
22 publicly.

23 A. (Witness Robinson) And, again, I will say
24 that their costs are different than our costs as well.

25 COMMISSIONER PRIDEMORE: As is their

1 regulatory structure.

2 A. (Witness Robinson) And as their regulatory
3 structure, they do not file an IRP with this Commission.
4 They have individual boards that govern their planning
5 process.

6 Q. So this first page includes the detail of a
7 project name? Do you see that?

8 A. (Witness Robinson) Are you still on 32?

9 Q. Yes.

10 A. (Witness Robinson) Okay. Project name?

11 Q. Yes. And it also includes details of the
12 scope of the project, including that this particular
13 project is 10 miles of 230kV lines from point A, which it
14 defines, to point B, which it defines. Do you see that?

15 A. (Witness Robinson) Yes.

16 Q. And the project cut-in date is June 2027.
17 Can you share with the Commission what the project cut-in
18 date tends to be, what that reflects?

19 A. (Witness Robinson) That's the -- so this is a
20 230kV line. That would be the projected date that they're
21 going to energize this line and put it in service.

22 Q. And then it lists a number of direct charges
23 like construction, contract labor, owner-furnished
24 material, land, professional services, legal, project
25 contingency, and escalation. And then a total for all of

1 that together. Do you see that?

2 A. (Witness Robinson) I do.

3 Q. And at the bottom, it includes assumptions
4 that the estimate is based on. It recognizes that this
5 estimate is just that, it's an estimate. And it's based
6 on an estimate of \$3.5 million per mile. Do you see that?

7 A. (Witness Robinson) I do.

8 Q. It also describes the contingency costs that
9 are set as a percentage of direct costs.

10 A. (Witness Robinson) I do, and I would say that
11 GTC has their separate project management process. They
12 have their own relationship with vendors, and that they
13 have access to low-cost capital through USDA and the REA.
14 So I would imagine that these documents and disclosures
15 are required to access that low-cost capital.

16 Q. Okay. Gentlemen, are you familiar with the
17 updated trade secret assertions that were filed in this
18 case yesterday?

19 A. (Witness Robinson) I'm familiar with the one
20 I signed.

21 Q. All right.

22 A. (Witness Bowers) And I'm somewhat familiar
23 with the one that, I believe, Jeffrey Grubb signed.

24 Q. So, Mr. Robinson, let's look at yours. The
25 updated filing that you made has the same format as the

1 trade secret assertion that was filed with the IRP, but
2 the update appears to be using language that is specific
3 to the outage information from Exhibit 7 that you filed
4 yesterday.

5 A. (Witness Robinson) Can you -- I don't have a
6 copy of what I filed earlier this week. Can you provide
7 me a copy? I do have a copy of what we filed in January
8 because it's in your folder.

9 Q. Yeah.

10 A. (Witness Robinson) Your binder.

11 MS. WHITFIELD: May Ms. Chandra approach?

12 CHAIRMAN SHAW: Sure.

13 BY MS. WHITFIELD:

14 Q. And I just want clarity around whether this
15 updated affidavit applies -- is intended to replace the
16 prior affidavit in its entirety, or whether this updated
17 affidavit is designed to relate solely to the new exhibit
18 that was filed with it yesterday.

19 A. (Witness Robinson) And what you've given me
20 here is a copy of what we submitted in January, and then
21 an updated that we submitted earlier this week; is that
22 correct?

23 Q. Yes.

24 A. (Witness Robinson) And where specifically are
25 you mentioning the difference in language? I see you've

1 got some highlighted sections here.

2 Q. The highlights generally reflect the new
3 language. And this may be a question your counsel could
4 clarify.

5 MR. HEWITSON: The updated trade secret
6 assertions address the specific documents that were
7 filed yesterday, and only those documents. They're
8 not meant to replace the other trade secret
9 assertions.

10 MS. WHITFIELD: Thank you.

11 With that, nothing further, Gentlemen. Thank
12 you.

13 MR. HUBBERT: Thank you.

14 MR. BOWERS: Thank you.

15 MR. ROBINSON: Thank you.

16 CHAIRMAN SHAW: Do you guys need a break?

17 MR. BOWERS: What's left?

18 CHAIRMAN SHAW: Redirect. How much time do
19 you need?

20 MR. HEWITSON: Not long. If anyone else
21 needs a break, I'm happy to break beforehand, but
22 it's not going to be very long.

23 CHAIRMAN SHAW: Keep going.

24 REDIRECT EXAMINATION

25

1 BY MR. HEWITSON:

2 Q. All right, gentlemen. I want to ask you a
3 couple questions just to follow up on the questions you
4 got from Ms. Whitfield, on just a couple of the documents.
5 If you look at Exhibit 2A. I believe, Mr. Hubbert, those
6 questions -- these questions will pertain to you. This
7 was GIPL Exhibit 22 and GIPL Exhibit 21 that were provided
8 to you. GIPL Exhibit 21 was the response to BAI-1-1,
9 Attachment A, and GIPL 22 was the estimated net impacts to
10 customers in the 2023 IRP update. Do you have those in
11 front of you?

12 A. (Witness Bowers) Yes, we do.

13 Q. Okay. And so this is information on rate
14 impacts for specific resources; is that correct?

15 A. (Witness Bowers) That is correct.

16 Q. Okay. But that is not the same as the
17 information that's contained in Exhibit 2A into GIPL's
18 motion, is it?

19 A. (Witness Hubbert) That is correct. It is not
20 the same.

21 Q. Okay. Exhibit 2A includes more information
22 than simply the revenue requirements for specific
23 resources. Would that be correct?

24 A. (Witness Hubbert) That is correct.

25 Q. Okay. And are there other differences in the

1 information contained in Exhibit 2A that are different
2 than the -- that is different than the information
3 contained in Exhibits 21 and 22?

4 A. (Witness Hubbert) Yes, as I mentioned
5 earlier. So it would include all of the variable costs
6 for the existing fleet, as well as the fixed costs and
7 variable costs for the things that were being requested
8 that were in the modeling in this IRP, as well as the
9 generic resources.

10 Q. Okay. And what about the information at the
11 top of Exhibit 2A, related to AFUDC and cost of capital
12 information, that information is not included in Exhibits
13 21 and 22; is it?

14 A. (Witness Bowers) Checking really quickly,
15 Steve.

16 A. (Witness Hubbert) It does not appear to be
17 directly included, but what we don't know is, is it
18 embedded in some of the analyses that that was in those
19 filings.

20 Q. Right. And I guess the question is:
21 Exhibit 2A has that provided prominently on the top of the
22 page, whereas that information is not provided in Exhibits
23 21 and 22; is it?

24 A. (Witness Hubbert) That's correct.

25 A. (Witness Bowers) It does appear that only

1 the -- I see the capital structure in here, which we
2 provide in the public disclosure, unredacted.

3 Q. Of 2A as well? It's unredacted in both
4 documents; right?

5 A. (Witness Bowers) Yes, correct.

6 Q. And despite Ms. Whitfield's use of the terms
7 like "revenue requirement" that are in both documents,
8 these exhibits, Exhibit 21 and 22, that GIPL has provided
9 for review, and Exhibit 2A, do not contain the same
10 information, even though it -- they both contain
11 information called "revenue requirements," it's not the
12 same information; is it?

13 A. (Witness Hubbert) That's correct.

14 Q. Okay. All right. Can we look at -- I think
15 I'm going to skip to Exhibit 6A. And specifically, this
16 is the -- oh, this is the table. I think it was called
17 Table 6, but it was the exhibit from staff testimony,
18 STF-NHSW-6. It says Exhibit STF-NHSW-6, generic resource
19 cost. Do you see -- do you have that document in front of
20 you now?

21 A. (Witness Hubbert) I think we remember what
22 it looks like.

23 A. (Witness Bowers) We're locating it, yes.

24 Q. I'll give you a minute to locate it. There's
25 probably a little bit of paper in front of you.

1 A. (Witness Hubbert) I think we've located it.

2 Q. Okay. And so if -- I think it's the first
3 page of the table, which is kind of on the second page of
4 the exhibit, but it's the -- it's the table that
5 Ms. Whitfield was asking you questions about where it's
6 got -- on the first column on the left, GPC 2025 IRP, and
7 then under it is CT with SCR. And then you'll see the
8 blanked out boxes there where there's trade secret
9 information contained; right?

10 A. (Witness Hubbert) Right.

11 Q. Okay. Now, I know you did not prepare this
12 exhibit, but I want to ask you a couple of questions based
13 on your understanding of this exhibit. First, going
14 across the columns there, EIA AEO 2025, what does that
15 column represent?

16 A. (Witness Hubbert) That is Energy Information
17 Administration's annual energy outlook they produce each
18 year, and they provide an estimation of the overnight
19 capital cost for each of these technologies.

20 Q. Okay. And EIA is not a utility?

21 A. (Witness Hubbert) It is not a utility.

22 Q. Okay. NREL ATB 2024, M-O-D, that's the next
23 column. What is that information?

24 A. (Witness Hubbert) Very similar. It's
25 National Renewable Energy Lab, annual technology baseline

1 they produce each year. It does something very similar to
2 the EIA AEO, in that they estimate cost and performance
3 characteristics for the different technologies. Also make
4 it publicly available.

5 Q. Also not a utility.

6 A. (Witness Hubbert) Not a utility.

7 Q. Okay. So looking at this entire document,
8 the blacked out boxes is the information that we know that
9 we have provided as trade secret information only, in no
10 public disclosure form; right? For the Georgia Power
11 information?

12 A. (Witness Hubbert) Correct.

13 Q. Okay. There are blank boxes throughout this
14 table that are not blacked out but are just left blank.
15 Is that presumably because that information has not been
16 provided by those entities as public disclosure?

17 A. (Witness Hubbert) That's a possibility. I
18 really can't speak to what the other utilities are
19 providing publicly or not, but that's very possible.

20 Q. Okay. And so if this document was to be a
21 fair representation, putting Georgia Power on the same
22 level as those, rather than leaving those just blank with
23 no information, they should be blacked out. Wouldn't you
24 agree?

25 A. (Witness Hubbert) Yes.

1 Q. Okay. And if you look at the total columns
2 taking Georgia Power -- the two filings by Georgia Power
3 as one utility, and the two filings by Duke, South
4 Carolina, in the middle there, as one utility, I count --
5 and taking out EIA, taking out NREL. I count eight
6 utilities that are represented in this chart. Do you see
7 that?

8 A. (Witness Hubbert) Yes.

9 Q. Okay. And if you look across the table
10 there, only two of those utilities, Santee Cooper and
11 Indiana-Michigan Power, provide all of the information
12 that is listed on the left-hand column of this table; is
13 that correct?

14 A. (Witness Hubbert) Yes, that's correct.

15 Q. Okay. So six of the eight utilities don't
16 provide all of the information that GIPL is claiming
17 should be provided as public disclosure; is that correct?

18 A. (Witness Hubbert) Correct.

19 Q. Okay. Let's look at Exhibit 26, if we can.
20 This is the Oglethorpe Power combined cycle project
21 update. I'm looking at page 4 where Ms. Whitfield was
22 asking you questions about that. In the second bullet --
23 second main bullet, I guess, it says: "Preliminary cost
24 estimate for this facility is 1.8 to \$2.3 billion." Do
25 you see that?

1 A. (Witness Hubbert) We do, yes.

2 Q. Okay. And so that is a preliminary cost
3 estimate, as you understand it; is that correct?

4 A. (Witness Hubbert) That is my understanding.

5 Q. And the range of this preliminary cost
6 estimate is half a billion dollars; right? \$500 million?
7 Is that correct?

8 A. (Witness Hubbert) Yes.

9 Q. Okay. And so it's not like Oglethorpe Power
10 was revealing very specific information regarding their
11 specific and actual costs in this document; is that a fair
12 statement?

13 A. (Witness Hubbert) I think that's a fair
14 statement.

15 MR. HEWITSON: Okay. Thank you, Gentlemen.

16 Those are all the questions I have for this panel.

17 I ask that, unless Commissioners have further
18 questions for them, they be excused.

19 CHAIRMAN SHAW: Thank you, Mr. Hewitson.
20 Commissioners?

21 (No response.)

22 CHAIRMAN SHAW: All right, gentlemen. Thank
23 you for your time. You can be excused.

24 MR. HEWITSON: Thank you.

25 CHAIRMAN SHAW: Ms. Whitfield, did you have a

1 witness --

2 MS. WHITFIELD: I do.

3 CHAIRMAN SHAW: -- or witnesses, rather?

4 MS. WHITFIELD: Yes.

5 CHAIRMAN SHAW: All right.

6 MS. WHITFIELD: GIPL and Southface would like
7 to call Mr. Patrylak to the stand.

8 CHAIRMAN SHAW: Wait. Ms. Whitfield, this
9 would be a good time, I think, to take a quick
10 break.

11 MS. WHITFIELD: Sure.

12 CHAIRMAN SHAW: It's 11:48. We'll try to get
13 back started at 11:55.

14 (Whereupon a break was taken.)

15 CHAIRMAN SHAW: All right. Let's go ahead
16 and get started. Thank you all for the break.
17 Okay. Picking up where we left off on the
18 hearing -- on the motion. At this time,
19 Ms. Whitfield, I'll let you swear in your witness.

20 Thereupon,

21 ROBERT PATRYLAK,
22 having been duly sworn, testified as follows:

23 DIRECT EXAMINATION

24 BY MS. WHITFIELD:

25 Q. Could you please state your full name for the

1 record and spell your last name for the court reporter?

2 A. Yeah. My name is Rob Patrylak and --

3 CHAIRMAN SHAW: Can you pull that mic just a
4 little bit closer to you? Some of us are hard of
5 hearing.

6 MR. PATRYLAK: Yeah. Is this better?

7 A. My name is Robert Alan Patrylak, and the last
8 name is spelled P-A-T-R-Y-L-A-K.

9 Q. Mr. Patrylak, what is -- where do you
10 currently work?

11 A. I work for my firm, Patrylak Energy Advisors,
12 based in Marietta, Georgia.

13 Q. In school, what did you study or get your
14 degree in?

15 A. So I have an undergraduate degree in
16 mechanical engineering from Penn State and a Master's in
17 Business Administration from Saint Joseph's University.

18 Q. And apologies that we didn't do this ahead of
19 time, but if Ms. Chandra could approach, she'll hand out
20 your CV.

21 A. Great. Thank you.

22 Q. And is this CV true and correct, to the best
23 of your knowledge?

24 A. It is.

25 (The documents referred to were premarked for

1 identification as GIPL/Southface Exhibit 33.)

2 Q. The CV has been marked as GIPL/Southface
3 Exhibit 33. Mr. Patrylak, how long have you been working
4 in the utility industry?

5 A. So I've been in the power and energy and
6 utility industry 37 years.

7 Q. And if you could, at a very high level, give
8 the Commissioners an outline of your career.

9 A. Yeah. So I started my career at an
10 investor-owned utility. It was called Philadelphia
11 Electric Company, which is part of Exelon. Spent the
12 first ten years of my career, you know, going -- starting
13 in the generation side of the business, moving over to gas
14 operations and electric transmission and distribution.

15 From there, I moved on to -- went into
16 consulting, working for Navigant Consulting for about five
17 years. And I went in -- I worked primarily out on Long
18 Island as a transmission and distribution operations
19 expert, and started to get into resource planning during
20 that time.

21 Would you like me to continue?

22 Q. Yes. You're doing great. Thank you.

23 A. From there, I moved to a company called the
24 Energy Authority in Jacksonville. They're a trading and
25 risk management organization, where they trade on behalf

1 of public power nationally. So here in the Southeast, the
2 Energy Authority serves and trades power for Santee Cooper
3 and *DEI and some of the utilities alike.

4 After my tenure there, I moved to Atlanta.
5 And that's why I'm here in Atlanta. I moved to work for a
6 company called New Energy Associates at the time. New
7 Energy Associates was a production cost modeling software
8 tool. They make tools like *Strategist and PROMOD and
9 basically all the tools. I understand -- you know,
10 Georgia Power uses AURORA, but it's a competing product to
11 that.

12 And when I came up to work for this company,
13 I was tasked with building a consulting business. And in
14 my time there, we built about a 60-person consulting
15 business that specialized in integrated resource planning,
16 market assessment. We did do some retail rate and
17 regulatory work as well.

18 After my time there, I moved to a company
19 called R.W. Beck, where I led -- where I led about a
20 35-person staff. Again, the practice area and the team
21 that I worked -- or that I led and worked in was focused
22 in integrated resource planning, market assessment work,
23 transmission planning work, etc.

24 So, you know, the first half of my career was
25 really focused in the industry, working at a utility or

1 companies that represent utilities. And then the latter
2 part of my years was at a consulting firm leading and
3 managing the type of subject matter that we're going to be
4 talking about today.

5 A couple other firms I want to mention that
6 I, you know, I also was a managing director at Black &
7 Veatch. So after leaving R.W. Beck and moving to Black &
8 Veatch, I led their integrated resource planning and
9 market assessment group, as well as their rates and retail
10 for providing consulting. And we worked -- obviously,
11 you're familiar with Black & Veatch. They're primarily an
12 engineering, procurement, and construction firm, very
13 large firm, and they had a consulting -- management
14 consulting practice.

15 From there, I moved to a company -- back to
16 Navigant Consulting. This time, instead of being part of
17 the integrated resource planning and market assessment
18 team, I went back to run that team and the transmission
19 planning team. And then about five years ago, I left that
20 firm and started my firm, Patrylak Energy Advisors, doing
21 similar work that I just described.

22 Q. Mr. Patrylak, have your clients included
23 statewide utilities?

24 A. Yes.

25 Q. And municipal utilities?

1 A. Yes.

2 Q. Regional organizations?

3 A. Yes.

4 Q. Have you had clients in the private equity
5 space?

6 A. Yes.

7 Q. And investment banking space?

8 A. Yes.

9 Q. Could you just briefly share with the
10 Commission the context for having clients in the private
11 equity and investment banking space for your testimony?

12 A. Yeah. I mean, in this type of work, you
13 know -- basically, in integrated resource planning or
14 market assessment work, what you're -- what you're doing
15 is you're simulating the market and you're developing
16 views on, you know, what it costs to run a resource and
17 what kind of revenue that resource is going to receive.
18 And so we, you know, not only did integrated resource
19 planning, but a lot of times we helped investment banks
20 and private equity in making investment decisions into
21 generation portfolios, etc, acquisition of companies, you
22 know. All those types of things.

23 Q. And you mentioned, when you were summarizing
24 your career, integrated resource planning and/or resource
25 planning specifically. Could you share with the

1 Commission what your experience is, generally, with
2 respect to integrated resource planning?

3 A. Yeah. So when -- you know, when I first came
4 to Atlanta and was working for New Energy Associates and
5 building that team, which now is Ventyx and Mitsubishi
6 Ventyx, it's a much larger organization. You know, what
7 we would do is, we would -- we would actually work with
8 utilities and teach young utility planners on how to do
9 integrated resource planning.

10 And the focus of integrated resource planning
11 is to have a well thought-out plan for the future that
12 includes environmental reliability and economics in
13 developing the best strategy for a utility to move
14 forward, and what the integrated resource planning
15 emphasizes is the importance of transparency. And so, you
16 know, we -- I've been involved in a lot of those types of
17 efforts.

18 COMMISSIONER MCDONALD: Would not service be
19 a part of that?

20 MR. PATRYLAK: Would what?

21 COMMISSIONER MCDONALD: Would not service be
22 a part -- you're going through the litany of things
23 that are involved in a IRP, but you didn't mention
24 service to customers because --

25 MR. PATRYLAK: Oh, yeah. So transmission and

1 distribution service. So, actually, like the
2 responding to -- you're saying the, you know,
3 outages and those types of things, maintaining the
4 system? Is that what you're referring to when you
5 say service?

6 COMMISSIONER MCDONALD: No, I was just
7 referring to the things that you said.

8 MR. PATRYLAK: Oh.

9 COMMISSIONER MCDONALD: That you didn't say.

10 MR. PATRYLAK: That I didn't say?

11 COMMISSIONER MCDONALD: I lost the customer
12 in all the things that you say are involved in an
13 IRP.

14 MR. PATRYLAK: Oh, okay. Okay.

15 COMMISSIONER MCDONALD: I never did hear "the
16 customer."

17 MR. PATRYLAK: The customer being involved.
18 I'm sorry. So in an integrated resource plan,
19 stakeholders are a key component of that, and
20 getting input on, you know, what's important and
21 what's valued to the stakeholders to make the best
22 decisions, or to at least provide input to the
23 utility, so they can make more informed decisions
24 about their base.

25 COMMISSIONER PRIDEMORE: But stakeholders

1 don't always represent customers. Here at our
2 Commission, for the most part, the stakeholders,
3 the intervenors, represent their own private
4 interests and those that pay them to come in here
5 and represent those interests on their behalf.

6 So customers here at the Georgia Commission
7 are represented by five statewide-elected
8 commissioners who represent the people that sent us
9 here.

10 MR. PATRYLAK: Yeah, so I'm just completing
11 an integrated resource plan in Brownsville, Texas.
12 And we ran the stakeholder meetings as part of the
13 integrated resource planning process. And what we
14 did was, we developed a cross-section of
15 commercial, industrial, and residential customers.
16 And there were intervenors, as you might point out,
17 but we included -- we included the customer base,
18 and that's typically what we do when we do an
19 integrated resource plan.

20 COMMISSIONER PRIDEMORE: Texas has a very
21 different market structure than Georgia has. You
22 know, the single state ISO, you have a smaller
23 Commission that's appointed by the governor. You
24 have different arms that are also appointed within
25 the regulatory process at the Texas Legislature.

1 It's a very different market structure.

2 MR. PATRYLAK: Yeah. So that is just the --
3 that's the integrated resource plan I'm completing
4 right now, but I've done integrated resourcing
5 planning here in the Southeast. I've been part of
6 the integrated resource plan that we did when I was
7 at Black & Veatch for Santee Cooper. I've done
8 work for MEAG, you know. So I've done from -- you
9 know, I have exposure to clients here in the
10 Southeast. So I do understand the market, and I
11 appreciate, you know, what you're -- what you're
12 pointing out.

13 BY MS. WHITFIELD:

14 Q. And maybe to get to Commissioner McDonald's
15 concern, you would agree, correct, that an integrated
16 resource planning process prioritizes, typically,
17 reliability and cost?

18 A. Yes. Yeah. So it's -- it's three legs. The
19 way -- the way I always explained it, it's three legs:
20 Environmental, reliability, and costs. And what we used
21 in this latest integrated resource planning process where
22 we went with the stakeholders, we were trying to help them
23 provide input on what's most important, because not all
24 three are equally as important in a community. And so
25 that was the way that we've kind of approached that

1 process. Every integrated resource planning process is
2 different because, you know, as was pointed out, you know,
3 the areas are different, the regions are different, the
4 rules are different, and so you need to adapt an
5 integrated resource plan accordingly.

6 Q. In your work on integrated resource plans,
7 have you used modeling software to forecast long-term
8 revenue and cost streams for IRP scenario planning?

9 A. Yes. Yes, I have.

10 Q. Have you performed cost benefit analysis for
11 generation asset retirement studies?

12 A. Yes.

13 Q. Have you worked on financial modeling in the
14 IRP space?

15 A. Yes.

16 Q. Have you worked on energy procurement?

17 A. Yes.

18 Q. Could you describe for the Commission,
19 briefly, your experience with respect to procurement
20 processes for meeting energy needs?

21 A. Yes. So I've run requests for proposal
22 processes, not only to purchase capacity and energy, you
23 know, through -- you know, through a PPA, or something
24 like that, but also have managed and run the process to --
25 for engineering, construction, and procurement.

1 Q. Do you typically provide testimony, or have
2 you typically provided testimony over the course of your
3 career?

4 A. I've provided testimony, you know, a handful
5 of times. I haven't done a lot of testimony. But I've
6 done a lot of integrated resource planning, and I'm very
7 familiar with this subject matter.

8 Q. And is it fair to say your work is typically
9 behind the scenes?

10 A. Typically behind the scenes.

11 Q. Have you reviewed GIPL and Southface's
12 exhibits in this case, for which they're asking for
13 disclosure, specifically, GIPL and Southface's Exhibits
14 2A, 3A, 4A, 6A, and 8A?

15 A. Yes.

16 Q. Let's look at 2A, specifically.

17 A. Okay.

18 Q. And if you look at the second page of 2A,
19 you'll see that the total annual revenue requirements are
20 included here as an input.

21 A. Yes.

22 Q. And on page 1, it has the levelized price per
23 kilowatt hour?

24 A. Yes.

25 Q. What's generally -- in your experience, what

1 is generally the value of providing this kind of
2 information in an IRP?

3 A. So the way that we use it is we try to allow
4 visibility as to when you're comparing plans, what's the
5 incremental cost differences between the different -- you
6 know, the different portfolios that you're looking at.

7 Q. Based on your experience, is it reasonable to
8 conclude that publicly disclosing revenue requirements of
9 an IRP portfolio could cause a utility economic harm?

10 A. No.

11 Q. Why not?

12 A. You know, typically a revenue requirement
13 number, you know, it's -- it's an aggregated number. And
14 so it gives you relative -- where you can compare relative
15 from one plan to the other. But it really doesn't give
16 you the detail that you need to -- you know, hearing the
17 other arguments, you know, to -- you know, from my
18 perspective to give someone a competitive advantage that's
19 bidding on something. You know, I just -- I wouldn't be
20 familiar with that.

21 Q. In your experience, is the kind of
22 information reflected in GIPL/Southface Exhibit 2A the
23 kind of information that utilities typically reveal?

24 A. Yeah, I think that these are -- this is
25 information that we've seen out there and we're going to

1 be looking at exhibits that demonstrate that.

2 Q. In your 30 years working on integrated
3 resource plans, have you ever heard of a utility suffering
4 economic harm from publicly disclosing revenue
5 requirements?

6 A. No.

7 Q. In your 30 years working on IRPs, have you
8 ever been asked to or observed reverse engineering of
9 revenue requirements to help provide another electric
10 company a competitive edge?

11 A. No.

12 Q. Georgia Power alleges that disclosing the
13 revenue requirements would provide competitors with
14 financial information that could lead them to manipulate
15 RFP proposals, causing higher prices for bill payers.
16 Based on your career and experience, is this a reasonable
17 fear?

18 A. No.

19 Q. Based on your experience, would disclosure of
20 the financial information in Exhibit 2A cause a bidder to
21 change its bid?

22 A. No. And when -- just clarification, the
23 bidder would be a transmission -- a transmission company
24 or a generation -- an IPP, is what you're referring to as
25 a bidder?

1 Q. Yes. Sure. Any kind of bidder for
2 contracting for utilities that you would have -- that
3 falls within your experience.

4 A. So when I -- when I worked at Black &
5 Veatch -- you know, we were a -- you know Black & Veatch,
6 I'm sure everyone knows, is a large transmission and
7 generation EPC. And I ran the integrated resource
8 planning group. And there was never a request for me to
9 look at an IRP to back re-engineer to help them with bids
10 or anything related to that.

11 Q. Let's take a look at Exhibit 3A, load growth
12 projections for large loads. In your experience
13 supporting IRPs, are you aware that utilities typically
14 disclose information about the projected growth in their
15 respective customer classes?

16 A. Yes, some do.

17 Q. So let's talk about large loads,
18 specifically. Do you have experience supporting the
19 players in the market who are responsible for identifying
20 the ideal locations for large loads?

21 A. I do.

22 Q. And could you describe for me the process of
23 how would one go about identifying a suitable utility for
24 their large loads needs?

25 A. Yeah. So, you know, specifically, I have

1 experience working for developers that create -- that
2 create areas where data centers could be constructed. And
3 there's numerous things in choosing a location. There's
4 security, there's location relative to transmission.
5 They're interested in location relative to generation
6 pipelines, etc. And typically, when there is a data
7 center, they know who's -- who can supply power. And so
8 what they typically do is, they reach out to the utilities
9 in a confidential manner and start conversations to see
10 who could -- who could best supply.

11 Q. And as part of those conversations, do
12 utilities typically share with those interested customers
13 whether they can or cannot serve their needs?

14 A. Yes.

15 Q. Based on your experience, is it reasonable to
16 conclude that disclosure of large load peak information
17 could cause economic harm to a utility?

18 A. No.

19 Q. Why not?

20 A. Well, like I said, I don't think if -- if a
21 large load is coming into the area, they are going to be
22 approaching everybody that they can buy from it, and
23 they're going to see where they can get the best price for
24 the most reliable service. And typically these data
25 centers need multiple feeds and they want on-site

1 generation, so there's multiple things that are going on.

2 COMMISSIONER MCDONALD: Is best price before
3 reliable service?

4 MR. PATRYLAK: Not for -- I mean, it depends
5 on the application, but typically for data center,
6 reliability is a, you know, among the highest and
7 most important.

8 BY MS. WHITFIELD:

9 Q. Let's take a look at Exhibit 6A, please.

10 A. I'm sorry. Say that again?

11 Q. 6A.

12 A. 6A.

13 Q. From your experience with IRP resource
14 planning, are you familiar with the utility practice of
15 using generic inputs to model how various kinds of
16 electricity generators could behave and how those
17 generators could add costs to the system?

18 A. Yes.

19 Q. In your experience, is there any value to
20 sharing these generic cost assumptions with the public?

21 A. The value in sharing with the public is it
22 allows more transparency in the process, and it allows
23 them to see how the different technologies compare in
24 price.

25 Q. Is it -- in your opinion, based on your

1 experience, is it reasonable to conclude that the utility
2 could suffer economic harm based on the public disclosure
3 of this information?

4 A. I don't see how a utility would, no. No.

5 Q. Why not?

6 A. Well, these are -- these are basically
7 generic units that are put in from a modeling perspective
8 to help develop an optimal plan. And so, you know, the
9 algorithm, you know, runs through and it -- it helps build
10 out portfolios and it -- under various assumptions. It
11 doesn't in any way inform a bidder, like a generation or a
12 transmission -- you know, what they should charge anybody,
13 you know, for that particular project. It's just not used
14 in that way. They're generic.

15 And typically, you can -- you can call up and
16 you could make your own -- where you can buy these, you
17 know, from different consultants. But, you know, this
18 is -- you know, if you call up General Electric, or, you
19 know, whoever you want to, you know, you want to speak
20 with, you can contact them and they will share information
21 with you at a level, you know. They're not going to give
22 you the exact quotes. You know, that might require more
23 requirements, but at a high level, it provides
24 transparency.

25

1 Q. In your career, have you had the opportunity
2 to work with sophisticated customers who need to price out
3 potential energy needs and/or potential energy projects?

4 A. I have.

5 Q. And what kind of information do those
6 customers rely on in your experience?

7 A. Maybe if you can reframe it.

8 Q. Yeah, sure. In your experience working with
9 customers putting together a potential bid for a
10 generator, let's say.

11 A. Okay.

12 Q. What kind of information would that customer
13 use and rely upon?

14 A. Okay. So, you know, it would -- it would
15 need control of the particular technology. So it's
16 already worked through -- in order to develop a bid, it's
17 going to have control of that technology and know pricing
18 and, you know, performance information. It's going to
19 need to have an understanding of either a lease or own the
20 property and know the costs related to that. It's going
21 to need some, you know, energy supply. It's going to
22 need, you know, water.

23 You know, there's a lot of things that will
24 go into -- and then the cost of labor in that region to
25 actually -- you know, to install it, to construct and

1 build it, the engineering required. So there's a lot of
2 pieces that go into putting together a bid. This type of
3 information is not a consideration. Any sophisticated
4 bidder.

5 Q. In your 30-year career, have you ever been
6 asked to use generic inputs from a utility's IRP modeling
7 to help an energy contractor develop price assumptions for
8 their product?

9 A. No.

10 Q. Is generic information of this sort useful to
11 develop pricing for resources in the energy market by the
12 time it's published in an IRP?

13 A. Because of the changing -- how quickly
14 technology costs change, sometimes -- you know, time is
15 the enemy, and it changes actually before it's published.
16 But it's still -- you know, using data, even if it's a
17 little bit dated, is still useful.

18 Q. Let's take a look at GIPL/Southface
19 Exhibit 8A.

20 A. Yes.

21 Q. I should have asked you at the outset, and I
22 didn't, so I'll ask you now: Mr. Patrylak, do you have
23 access to trade secret information in this docket?

24 A. In this docket, no.

25 Q. What is your understanding of the information

1 that is redacted in Exhibit 8A?

2 A. So these -- this is information in the
3 ten-year plan that is redacting cost data. And I -- you
4 know, at this level -- I believe that at this level and at
5 this disclosure, this could be shared.

6 Q. Could you please remind the Commission about
7 your experience with transmission specifically over the
8 course of your career?

9 A. Yeah. So when you -- when -- I've done a
10 significant amount of work in generation and in
11 transmission. I've actually done -- I've actually managed
12 a request for proposals, basically an EPC for transmission
13 over my career. As part of integrated resource planning,
14 transmission is always a component that's considered, to
15 be able to access generation from another area.

16 So it's evaluated as part of an integrated
17 resource plan. My team and I have done congestion
18 analysis studies that support, you know -- support
19 financing and investments in these areas.

20 Q. Is it reasonable to conclude that the utility
21 could suffer economic harm based on sharing this
22 information publicly at this level?

23 A. I think that -- I think that from a -- from a
24 harm perspective, these are estimated costs. These are
25 not definitive costs. So I -- you know, my experience is

1 transmission. Anybody that would be bidding on these
2 projects would be developing their estimated bids based
3 on, again, you know, labor in the area, the cost of the
4 materials, you know, all those different components. They
5 would not be using this to develop their cost.

6 Q. In your experience working on transmission,
7 do utilities ever provide their projected total project
8 cost?

9 A. Would you repeat that question?

10 Q. Sure. In your experience working on
11 transmission, do utilities ever provide their projected
12 total project cost?

13 A. They do.

14 Q. And how does that total project cost
15 information change the bidding process?

16 A. You know, I'm not -- so when you have
17 planning type and estimates, I'm not sure that it changes
18 the bidding -- the bidding process. You know, that's a --
19 you know, if there's a transmission company in the area,
20 and Georgia Power would estimate that it was, you know, X
21 dollars, well, you know, all those transmission companies
22 already know that. They already know what a project is
23 going to cost, probably better than Georgia Power because
24 they're doing multiple ones all across the country.

25 Q. So a total project cost -- a total project

1 cost estimate, if it -- in your experience, when it's
2 provided to bidders, does it inform -- would a bidder
3 increase their price by a dollar, for example, because of
4 the total price provided to them?

5 A. I don't -- I don't believe it would. I think
6 that bidders are -- are putting in bids against other
7 competitors, and they're all buying products from
8 suppliers. They're all competing for labor. And, you
9 know, they know what the labor costs are. They know, you
10 know, all those different components that, you know, put
11 together a -- they're putting together a bid, and they're
12 not trying to beat an estimate from an -- you know,
13 from -- that they read on an IRP, they're trying to beat
14 one of the other competitors that's bidding on this. And
15 they're all sharpening their pencils, and they're all
16 trying to to win the work. That's my experience.

17 MS. WHITFIELD: I have no further questions
18 on direct. Mr. Patrylak is available for questions
19 from the Commission and cross-examination.

20 CHAIRMAN SHAW: Thank you, Ms. Whitfield.

21 Commissioners, any questions for the witness?

22 (No response.)

23 CHAIRMAN SHAW: All right. Georgia Power.

24 MR. HEWITSON: Thank you, Mr. Chairman.

25 CROSS-EXAMINATION

1 BY MR. HEWITSON:

2 Q. Mr. Patrylak, Patrylak?

3 A. Patrylak, yes.

4 Q. Patrylak. Good to meet you. My name is
5 Steve Hewitson.

6 A. Nice to meet you.

7 Q. I represent Georgia Power Company. I do have
8 a few questions for you. Regarding your CV, I did not see
9 there -- you've never worked for Southern Company or any
10 of its operating companies; right?

11 A. Right. No, I haven't.

12 Q. And I don't recall you, but have you ever
13 participated in a Georgia Power IRP before this
14 Commission?

15 A. Not before this Commission. No.

16 Q. Okay. And you did not sign a non-disclosure
17 agreement in this case; is that right?

18 A. That's correct.

19 Q. Okay. So your opinions of what trade secret
20 information can be released are done solely based off of
21 public disclosure forms. Is that my understanding?

22 A. Yeah. I mean -- yes, yes.

23 Q. Okay. So you never looked at the trade
24 secret information?

25 A. No.

1 Q. Okay. Did you provide, in your direct
2 testimony, any analysis regarding a quantitative analysis
3 of how harm could be derived from the manipulation of an
4 RFP or a bid process?

5 A. No.

6 Q. Okay. You spoke of transparency in
7 integrated resource planning in other states. Did you
8 undertake any evaluation of the amount or type of
9 information that was redacted in the 2016 IRP compared to
10 this IRP in 2025?

11 A. No. You're talking about the Georgia --
12 Georgia Power? No, I have not reviewed that.

13 Q. Did you review the 2016 IRP at all?

14 A. No.

15 Q. Okay. Did you undertake an analysis of the
16 type and amount of information that was redacted in the
17 2019 IRP compared to the 2025 IRP?

18 A. No.

19 Q. Did you review the 2019 IRP at all?

20 A. No.

21 Q. Okay. Did you do an analysis of the type and
22 amount of information that was redacted in the 2022 IRP
23 compared to the 2025 IRP?

24 A. No.

25 Q. Did you review the 2022 IRP at all?

1 A. No.

2 Q. Okay. Did you review the entirety of Georgia
3 Power's 2025 IRP document?

4 A. I reviewed it at a high level.

5 Q. Could you please explain what a high level
6 means? Did you read the entire executive summary?

7 A. Yes.

8 Q. Okay. Did you read the entire technical
9 appendix, volume 3 of the transmission plan?

10 A. No.

11 Q. Did you review any data requests or -- well,
12 did you review any data requests?

13 A. No.

14 Q. You didn't review any data requests?

15 A. No.

16 Q. Okay. Did you review any testimony -- direct
17 testimony or rebuttal testimony filed by Georgia Power?

18 A. No.

19 Q. Did you review any of the other technical
20 appendices that were provided in the 2025 IRP?

21 A. No.

22 Q. Would it be safe to say that if there is
23 publicly available information that could be used in
24 combination with the specific trade secret information
25 that is at the subject of this hearing here today, you

1 would not be able to provide an informed analysis or
2 opinion as to whether the use of the publicly available
3 information from other parts could be harmful to Georgia
4 Power or Georgia Power's customers?

5 A. It is possible.

6 Q. It is possible to say that you would not be
7 able to give that opinion?

8 A. That's right.

9 Q. And you're not giving that opinion today
10 because you didn't review that information; is that
11 correct?

12 A. That is correct.

13 Q. Do you agree -- oh, when you refer to
14 stakeholders, like the Brownville IRP process that you're
15 talking about, when you say the word "stakeholders," who
16 specifically do you mean?

17 A. So stakeholders are basically customers --
18 basically customers. And there are other groups that have
19 interest and have participated in these meetings as well.

20 Q. Okay. Do those other groups participate in
21 the Brownville IRP process?

22 A. Yeah, there are some other -- there's a --
23 it's a -- kind of a cross-section. It's designed to be a
24 cross-section, but anybody's -- it's open to the public.
25 So anybody can participate.

1 Q. In your stakeholder meetings?

2 A. Yes.

3 Q. Okay. Is there a process before -- what does
4 Texas call their board, the PUC?

5 COMMISSIONER PRIDEMORE: PUC.

6 MR. HEWITSON: PUC.

7 MR. PATRYLAK: No. No.

8 BY MR. HEWITSON:

9 Q. Is there an IRP process before the Texas PUC?

10 A. No. It's a -- this is a public utility, so
11 it doesn't need to go through that.

12 Q. Okay. So there is no process by which
13 Brownville Utilities goes to a Commission to ask
14 permission to do anything; right? Where those
15 participants could also participate in the process; is
16 that correct?

17 A. That's right. There's no process.

18 Q. Okay.

19 A. In that regard, yeah.

20 Q. So the only opportunity for them to get any
21 information about Brownville IRPs is to go through the
22 stakeholder process that you provide?

23 A. That's correct.

24 Q. Okay. But here in the state of Georgia, an
25 organization like GIPL could intervene in the IRP; is that

1 correct?

2 A. Yeah.

3 Q. A public witness could provide public comment
4 before any of the hearings in Georgia; right?

5 A. Yes.

6 Q. A public witness could review the IRP that's
7 filed and provided online; is that correct?

8 A. Could you -- say that one more time. I'm
9 sorry.

10 Q. Could review the IRP that is posted on the
11 Public Service Commission's website; right?

12 A. Yeah. In Georgia, yeah.

13 Q. Yeah. And in Georgia, anyone can go on to
14 the Public Service Commission's website and review any of
15 the thousands of data requests that Georgia Power responds
16 to in response to the Public Interest Advocacy Staff's
17 questions; is that correct?

18 A. Yes. Yeah.

19 Q. Yeah. And they could also watch the
20 proceedings, unfortunately, on YouTube. And they are not
21 only broadcast live, but they are also, for the benefit of
22 all, recorded and are maintained on the Public Service
23 Commission's website; is that correct?

24 A. Yes, I assume so.

25 Q. So the example you give in Texas is that

1 Brownville Utility, that doesn't go through a Commission
2 proceeding for its IRPs, holds a stakeholder process where
3 you tell the public what's in the IRP compared to the
4 Georgia Power process, that we just reviewed all of the
5 ways that somebody can gain information on the IRP; is
6 that -- is that a fair comparison?

7 A. Yeah. I mean, but, you know, the process,
8 the stakeholder process -- and that's not the only IRP
9 that I've ever been involved in. But the process is -- I
10 was just using that as an example that it's a -- somebody
11 asked me what a stakeholder meeting looked like and I
12 said, you know, it involves a cross-section of the public,
13 so I was just explaining that.

14 Q. And did you provide as part of your testimony
15 any of the presentation -- I assume you give presentations
16 to the public?

17 A. Yes.

18 Q. Did you provide, as part of your testimony,
19 any of the public -- or any of the presentations that you
20 provide to the public during these stakeholder meetings
21 that would give this Commission an indication of the level
22 of detail of information that you're providing to the
23 public?

24 A. No, we did not.

25 Q. Is there a website where they can go to to

1 review this information after that stakeholder meeting?

2 A. They can go to the Brownsville website.

3 Q. Okay. And so the Brownsville website posts
4 all the information that's available to the public?

5 A. Yes.

6 Q. Okay. And does the Brownsville website post
7 things like the marginal cost of its transmission?

8 A. I don't -- I don't know -- I don't know
9 specifically what is posted on the, you know -- I haven't
10 gone through the Brownsville website in that -- in that
11 level of detail.

12 Q. Did you look to -- did you look at the
13 Brownsville website to compare whether the information
14 provided on the Brownsville website is the type of
15 information that's being challenged in this trade secret
16 motion by GIPL?

17 A. So I guess -- no, we -- I did not do that.

18 Q. Okay. So you didn't look to see if the
19 information provided in 2A, that's been identified as
20 trade secret, is provided by Brownsville; did you?

21 A. So 2A -- yeah, 2A we estimated -- we
22 estimated the impact of revenue requirements across the
23 plans. So we did an incremental revenue requirement, and
24 we shared that with the stakeholders.

25 Q. Well, yeah, but an incremental revenue

1 requirement, as you heard the Georgia Power witnesses
2 testify this morning, is also provided by Georgia Power in
3 an aggregate; right? Is that what you're talking about?

4 A. Yeah.

5 Q. So it's the same information that Georgia
6 Power provides. It's not the more detailed information
7 that Georgia Power has marked as trade secret, is that --
8 is that my understanding -- is my understanding correct?

9 A. Yeah.

10 Q. And do you agree that intervenors in the
11 Georgia Power process can have access to all of the
12 information that's been identified as trade secret with
13 the signing of a confidentiality agreement?

14 A. Yeah, I'm aware of that.

15 Q. Okay. And you're aware, then, that the
16 advocacy of any intervenor in this group is not harmed by
17 the identification of trade secret information, because
18 they can have access to that if they sign the agreement
19 and, therefore, can advocate for their clients; is that --
20 is that a fair statement?

21 A. That is true. But, you know, I guess once --
22 once the window closes, they can no longer utilize that
23 information if it's not public.

24 Q. I'm sorry. What do you mean by the window?

25 A. So once the confidentiality agreement window

1 closes, they're not able to, you know, utilize that.

2 Q. And when does that confidentiality agreement
3 end?

4 A. I'd have to look at the confidentiality
5 agreement.

6 Q. Okay. If I told you that it ends after the
7 Commission decision -- after an order is rendered and
8 after a time period for a motion for reconsideration,
9 would you -- would you accept that as when it ends?

10 A. Yeah, if you say so.

11 Q. So -- so the window ends after the hearings
12 on the IRP are complete; is that correct?

13 A. Okay. If that's -- yeah. Like I said, I
14 don't recall exactly what the confidentiality agreement
15 said.

16 Q. Okay.

17 A. But I'm aware that there is one.

18 Q. Okay. I did not get a chance to go through
19 your entire CV, which is very long. Is there a
20 Southeastern public -- public utility -- regulated utility
21 that you have done an IRP process for?

22 A. Not a regulated utility.

23 Q. Okay. So you've never done an IRP for a
24 regulated utility in the Southeast?

25 A. No.

1 Q. Okay. Speaking specifically to Exhibit 2A as
2 we were a little bit ago, are you aware that revenue
3 requirements can be combined with other publicly available
4 data to gain insight into specific costs for specific
5 technologies?

6 A. You know, again, I -- my view of it is, is if
7 it's aggregated, it's a very difficult exercise. Possible
8 somebody is able to glean some -- but my assessment would
9 be it would be of low confidence that they'd be able to
10 develop something that was significantly meaningful.

11 Q. Have you ever worked for a bidder in a
12 utility RFP?

13 A. Have I ever worked for a bidder in the
14 utility RFP? No, I typically worked on the utility side.

15 Q. Okay. Are you -- are you aware that bidders
16 into Georgia Power's RFPs, both renewable RFPs and
17 capacity RFPs, are often very sophisticated companies?

18 A. Yes.

19 Q. Okay. Are you aware that they spend a lot of
20 time and effort and money on resources to undertake market
21 intelligence to inform their bids?

22 A. Yeah, I would expect they would.

23 Q. Okay. And are you aware that they actually
24 have entire departments that review integrated resource
25 plans in other states around the country to help them

1 develop their bids in RFPs, especially Georgia Power's
2 RFPs?

3 A. So I'm not aware of that.

4 Q. Okay. Would it make sense to you that
5 somebody that's bidding for a contract that could be worth
6 hundreds of millions of dollars would probably do as much
7 market intelligence and research as it could?

8 A. So I worked for Black & Veatch, and to my
9 knowledge, no -- you know, during my time there, the EPC
10 on the transmission side or the generation side never came
11 to me and said, "hey, you guys are doing IRPs all over the
12 place, can you do this for us?" So they are not using
13 them.

14 Q. Black & Veatch is a contractor that does work
15 for projects bidding into the IRP; right?

16 A. Yes.

17 Q. Black & Veatch doesn't bid into specific
18 utility IRPs, does it?

19 A. They don't bid directly.

20 Q. Okay. So their review of IRPs would probably
21 be less important than an independent power producer
22 that's bidding a generation resource into an RFP; right?

23 A. If -- that's right, it could be.

24 Q. Okay. And Black & Veatch, I've had some
25 dealings with them, and I've actually been under a

1 non-disclosure agreement -- Black & Veatch requires its
2 counterparties in work to sign non-disclosure agreements;
3 right?

4 A. They do.

5 Q. And the reason Black & Veatch does that is
6 because there's information of Black & Veatch's that they
7 believe would be market sensitive and would harm their
8 competitive advantage in the marketplace if somebody were
9 to release that information; right?

10 A. Yes.

11 Q. It's sort of like a non-disclosure agreement
12 in the Georgia Power IRP; right?

13 A. Yeah. And I had to -- you know, in the work
14 that I did for Black & Veatch, we -- when we go through
15 the contract process, that's usually part of the
16 negotiation that goes on, is you talk about -- and
17 typically, there are -- you know, it's understood that if,
18 you know, if things are needed to be made public, they
19 will be.

20 Q. Okay. And because you've never worked for an
21 independent power producer that's bidding into our RFPs,
22 you have no ability to testify under oath -- or to any
23 experience as to whether those independent power producers
24 are manipulating their bids based on information they gain
25 through IRPs. Is that a fair statement?

1 A. That is correct.

2 Q. Okay. On Exhibit 6A, you were asked about
3 generic pricing for capacity resources. You were -- were
4 you in the hearing room -- and, I'm sorry, my back was
5 turned to you, if you were. Were you in the hearing room
6 when Georgia Power's witnesses were testifying?

7 A. I was listening.

8 Q. Okay. Okay. And did you hear the Georgia
9 Power witnesses Mr. Bower and Mr. Hubbert both discuss how
10 Georgia Power works with -- with contractors and works
11 with -- what's the word I'm thinking of? Works with
12 people that -- that build stuff for them to develop
13 specific pricing for the Southeastern region?

14 A. Yeah. So if I could paraphrase, my
15 understanding was, they're not using generic information.
16 It's -- it's -- they're using it based on labor prices and
17 other impacts of being in the Southeast.

18 Q. Yeah. And OEM was the word I was thinking,
19 was looking -- was struggling with to get. They have
20 specific conversations with the original equipment
21 manufacturers to develop more specific pricing specific to
22 the Southeastern region that would be -- that Georgia
23 Power includes as its generic or technology costs; right?

24 A. Yeah.

25 Q. Okay. And that more specific information,

1 because it's been developed for the Southeast region by
2 Georgia Power in conjunction with the original equipment
3 manufacturers, would probably be more valuable to somebody
4 bidding into an RFP than generic EIA information or NREL
5 information; would you agree with that?

6 A. Yes.

7 Q. Okay. So it would be -- there would be a
8 heightened reason to protect that information as a trade
9 secret or as confidential compared to the generic
10 information that's provided by NREL or EIA. Would you
11 agree with that?

12 A. I would. The question that was asked was
13 would the utility be harmed, and the utility, you know --
14 so I understand that there might be other parties that
15 want to keep that material confidential. But
16 specifically, Georgia Power -- would Georgia Power be
17 harmed, that was the question that I answered.

18 Q. If Georgia Power has to pay more for a
19 generation resource than it otherwise would have would --
20 do you agree that Georgia Power and its customers would be
21 harmed?

22 A. If it has to pay more for -- for what reason?
23 Why would it have to pay --

24 Q. If in an RFP bid, bidders are in -- are
25 inserting bids into the RFP process that are higher than

1 they otherwise would be, and Georgia Power pays more for
2 those generation resources, that would be a harm to
3 Georgia Power and its customers; do you agree?

4 A. That hypothetical example, yeah.

5 Q. Yeah.

6 A. I don't know what would cause them to bid
7 higher.

8 Q. Well, you don't, but you've never worked for
9 an independent power producer that bids into RFPs; right?

10 A. No, but --

11 Q. And you don't know what market intelligence
12 they undertake to figure out how to establish their bids;
13 right?

14 A. I -- like I said, no, I haven't worked
15 directly with them.

16 Q. Right. So you have no idea whether they use
17 this information to manipulate their bids into RFPs, thus
18 causing Georgia Power to pay more for generation
19 resources; do you?

20 A. I guess the part that I still feel strongly
21 about is, in a bidding process, they're competing against
22 other competitors. And so if there's information
23 released, all those competitors would have that same
24 information, and they all would be bidding on that
25 process, and they would be trying to undercut each other

1 because they don't -- coming in at a dollar more, or a
2 dollar less than whatever information that Georgia Power
3 has, that doesn't mean anything. They have to beat the
4 competitors, and -- you know, and so that's really how
5 that process, from my perspective, would work. That's
6 how, typically, RFPs work is they're bidding against each
7 other. They're not looking at, you know, estimates from
8 the utility.

9 Q. Are you aware that Georgia Power also submits
10 bids for self-build resources?

11 A. Submits bids?

12 Q. Yes.

13 A. Yeah.

14 Q. So Georgia Power also competes. So the
15 bidders are not just competing against themselves, they're
16 also competing about -- against Georgia Power; right?

17 A. Yes.

18 Q. Okay. And the bidders are not required to
19 disclose all of their market intelligence or their
20 analysis and how they develop their bid; is that correct?

21 A. That's correct.

22 MR. HEWITSON: Thank you, Mr. Patrylak.

23 That's all the questions I have for you today.

24 Thank you.

25 CHAIRMAN SHAW: Redirect?

1 MS. WHITFIELD: Just a few questions.

2 REDIRECT EXAMINATION

3 BY MS. WHITFIELD:

4 Q. Mr. Hewitson asked you if you had ever worked
5 for Southern Company or its subsidiaries, including
6 Georgia Power. You said no. Have you ever worked with
7 Southern Company or its subsidiaries, including Georgia
8 Power, in your career?

9 A. Yeah. And people on my teams over the years
10 have worked with Georgia -- Georgia Power and Southern
11 Company.

12 Q. Mr. Hewitson asked you --

13 COMMISSIONER PRIDEMORE: Can I ask, doing
14 what? Is that -- we changed our answer based upon
15 a preposition. If you worked with them, but you
16 didn't work for them, in what capacity did you and
17 your employees work with them?

18 MR. PATRYLAK: So they're -- so, for
19 instance, for the unregulated, in Alabama we
20 developed price forecasts, and I don't know if I
21 can --

22 MS. WHITFIELD: You don't need to say
23 specific company names, but I think Commissioner
24 Pridemore is looking for subject area of the work
25 that you've done --

1 MR. PATRYLAK: Subject --

2 COMMISSIONER PRIDEMORE: But if you've
3 worked --

4 MS. WHITFIELD: -- for Southern Company
5 groups.

6 COMMISSIONER PRIDEMORE: -- with a Southern
7 Company owned organization in Alabama, did you --
8 did you work with them as an intervenor in a case
9 that was filed? Did you work with them in an RFP
10 to procure generation?

11 MS. WHITFIELD: Who was your client? Not the
12 name, specifically, the description.

13 MR. HEWITSON: If this is based on his
14 information and his personal knowledge and what
15 he's done, I absolutely want to know the name of
16 the entity that he had worked for.

17 MS. WHITFIELD: Oh, okay.

18 MR. HEWITSON: I think that's important.

19 COMMISSIONER PRIDEMORE: That he worked
20 "with."

21 When you asked him, Mr. Hewitson, if he
22 worked "for," he said no, but Ms. Whitfield asked,
23 did you work "with," and he said, "yes." I want to
24 know the difference.

25 MS. WHITFIELD: Yeah, he represents Southern

1 Company?

2 MR. HEWITSON: Well, in this proceeding, I
3 represent Georgia Power Company.

4 MS. WHITFIELD: But can he take that as good?

5 MR. HEWITSON: I might -- I might need to
6 look at my notes to just make sure I know which
7 client I'm thinking of.

8 MS. WHITFIELD: Sure.

9 MR. PATRYLAK: If that'd be okay? Can I have
10 a minute?

11 MS. WHITFIELD: Sure.

12 MR. PATRYLAK: I'm going to have to open up a
13 computer. Sorry about that. I don't want to give
14 inaccurate --

15 COMMISSIONER PRIDEMORE: If it's in the
16 Cloud, there's a guest Wi-Fi.

17 MR. PATRYLAK: Okay. Thank you.

18 MS. WHITFIELD: And if the -- if the plan is
19 to make a decision today, I think it makes sense
20 for him to find the answer.

21 COMMISSIONER MCDONALD: I can't hear you.

22 MS. WHITFIELD: Sorry.

23 If the plan is to make a decision today by
24 the Commission, if you want to consider this issue
25 and make a decision, I think it makes sense for him

1 to find the answer so he can respond properly to
2 Commissioner Pridemore; otherwise, we could
3 supplement the record if there's going to be a
4 period of consideration before the decision.

5 CHAIRMAN SHAW: We'll give him a little more
6 time then.

7 MS. WHITFIELD: Okay.

8 CHAIRMAN SHAW: But as far as the plan, yeah,
9 staff is scheduled for a special admin, unless a
10 Commissioner would like to move it -- move it to a
11 regular, we will proceed with a special.

12 MS. WHITFIELD: Okay.

13 CHAIRMAN SHAW: After a quick break.

14 The only other thing I would add to that is
15 if advisory staff has anything they want to add,
16 that they -- if they have any additional questions,
17 that would also be helpful.

18 While we're kind of at a standstill, though,
19 I will say, Ms. Whitfield, thank you for all of
20 this information. It is very helpful, and it's
21 very well done, as always.

22 MS. WHITFIELD: Thank you, Commissioner.

23 And I'll take this opportunity to ask to move
24 our exhibits into evidence --

25 CHAIRMAN SHAW: So marked.

1 MS. WHITFIELD: -- as well, including the
2 summary tables, which will be marked as Exhibit 34.

3 (The documents referred to were premarked for
4 identification as GIPL/Southface Exhibit 34.)

5 COMMISSIONER MCDONALD: You must be getting
6 tired, Jennifer.

7 MS. WHITFIELD: I'm so tired.

8 COMMISSIONER MCDONALD: Your voice is fading
9 away.

10 MS. WHITFIELD: I'm sorry. Including the
11 summary table --

12 COMMISSIONER MCDONALD: If you want me to
13 hear what you're saying, you're going to have to
14 speak up.

15 MS. WHITFIELD: I am getting tired,
16 Commissioner. You're right.

17 CHAIRMAN SHAW: You got up early.

18 MS. WHITFIELD: I was asking for exhibits to
19 be moved into the record, including Exhibit 34,
20 which will be a collection of the summary tables
21 that have been provided today. Table 2, Table 3,
22 Table 4 -- there is no Table 4. Table 2, 3, 6, and
23 8.

24 COMMISSIONER PRIDEMORE: Is it to assume,
25 Ms. Whitfield, that the exhibits you've passed out

1 today, that there is trade secret/nonpublic
2 disclosure information in any of it?

3 MS. WHITFIELD: There is not trade secret
4 information in any of the exhibits I've handed out,
5 with the exception of the red folder. The red
6 folder includes --

7 COMMISSIONER PRIDEMORE: There's always one.

8 MS. WHITFIELD: The red folder does include
9 the trade secret version of the documents for which
10 we're asking disclosure.

11 COMMISSIONER PRIDEMORE: Thank you.

12 MS. WHITFIELD: Any luck, Mr. Patrylak? If
13 not, we can -- we can move on.

14 MR. PATRYLAK: Yeah, I would --

15 MS. WHITFIELD: Well, I'm sorry, I shouldn't
16 speak for you, Commissioner Pridemore. I'm sorry.

17 COMMISSIONER PRIDEMORE: What would --

18 MR. PATRYLAK: I mean, I could --

19 COMMISSIONER PRIDEMORE: Just tell us, if you
20 have a memory of working with them, what did you do
21 with them?

22 MR. PATRYLAK: So -- okay. So -- and it's
23 the -- it's the company --

24 COMMISSIONER MCDONALD: Talk into that
25 microphone, please.

1 MR. PATRYLAK: It's the company in
2 Birmingham, Alabama. So I think it's Southern
3 Power, but I'm not positive.

4 COMMISSIONER PRIDEMORE: Could be Southern
5 Power, could be Southern Company Services --

6 MR. PATRYLAK: So they bid -- they bid on
7 generation. They -- they are an unregulated
8 company that bought -- invested in generation
9 across the country. So we provided power price
10 forecasts and capacity price forecasts for them
11 that they used as part of their process. So we --
12 I was working at Navigant Consulting and our team
13 did that.

14 COMMISSIONER PRIDEMORE: Okay. So you worked
15 for them. You worked for them. You were employed
16 by somebody who contracted with them. You were
17 working for them.

18 MR. PATRYLAK: That's right. That's right,
19 but I don't recall the name. Is it Southern -- you
20 might know.

21 MS. WHITFIELD: That would be Southern Power?

22 MR. PATRYLAK: Southern Power?

23 MS. WHITFIELD: Yes.

24 MR. PATRYLAK: I didn't want to state it if I
25 am not positive. I can't remember.

1 MS. WHITFIELD: Okay. Have you ever worked
2 with or for Georgia Power, to your best
3 recollection in this moment?

4 MR. PATRYLAK: I think that folks on my team
5 have worked for Georgia Power, but I'd have to --

6 MS. WHITFIELD: That's sufficient. Thanks.

7 COMMISSIONER PRIDEMORE: Thank you.

8 BY MS. WHITFIELD:

9 Q. A few more questions. Mr. Hewitson asked you
10 a number of questions about how different financial
11 information in the voluminous IRPs could impact the
12 conclusions that you've provided today. Mr. Patrylak, are
13 you aware, through your work on IRPs, that they typically
14 provide, through IRPs or through rate cases, considerable
15 financial information and other detailed information?

16 A. They do.

17 Q. And did you take that into consideration when
18 reaching your conclusion that the -- it is not reasonable
19 to conclude that the utility would suffer harm from the
20 information in this -- at issue in this case?

21 A. Yes.

22 Q. You were asked a question about Black &
23 Veatch and discussed that when you were at Black & Veatch,
24 you negotiated non-disclosure agreements for the materials
25 you were providing.

1 A. Yes.

2 Q. And I believe you also mentioned that it was
3 understood that the materials may need to be disclosed as
4 part of that negotiating process.

5 A. Yes.

6 Q. Black & Veatch asked for a non-disclosure.
7 What is their business interest in asking for a
8 non-disclosure of that information?

9 A. Yeah. So we would resell, basically, that
10 information. You know, we would have a market view of,
11 you know, prices for generic resources, and we would
12 resell it. So we wouldn't want that out in the public.

13 Q. Black & Veatch wasn't selling power; correct?

14 A. We did not sell power, no.

15 MS. WHITFIELD: That's it for me. No further
16 questions. Thank you.

17 CHAIRMAN SHAW: Okay. Was there any other
18 witnesses?

19 MS. WHITFIELD: No other witnesses,
20 Commissioners.

21 CHAIRMAN SHAW: You've got all your
22 records --

23 MS. WHITFIELD: Yes.

24 CHAIRMAN SHAW: -- your evidence is marked?

25 MS. WHITFIELD: Yes.

1 CHAIRMAN SHAW: Okay. Thank you. Well,
2 Mr. Patrylak, thank you for your time today. You
3 can be excused.

4 MR. PATRYLAK: Thank you.

5 CHAIRMAN SHAW: All right. At this time,
6 unless there's a need for a break, we're going to
7 move on and move on to oral arguments. So we've
8 got 15 minutes of oral argument per side. And
9 we'll start with Georgia Power, and you can reserve
10 up to five minutes for response. So whenever
11 you're ready.

12 MR. HEWITSON: Do you want to let
13 Mr. Patrylak escape before we begin?

14 CHAIRMAN SHAW: He's excused. So,
15 Mr. Hewitson, just whenever you're ready. And,
16 Staff, I would ask you to record the -- keep up
17 with the time, too, please.

18 MR. HEWITSON: And I would, Mr. Chairman, ask
19 that I could reserve five minutes for a rebuttal or
20 responsive comment.

21 CHAIRMAN SHAW: That's -- that is approved in
22 the schedule.

23 MR. HEWITSON: Okay. Thank you.

24 I think it's important to set the stage for
25 this hearing, now that we've heard the evidence,

1 and talk a little bit about the motion itself
2 before getting into discussion about specific
3 documents. In the preamble to the motion, GIPL
4 explains the purpose of the motion, stating on
5 page 2 that, quote, "The ability to freely discuss
6 this information during Georgia Power's IRP
7 proceedings is crucial for the Commission, Georgia
8 Power customers, the public, and any other
9 stakeholders to adequately and accurately assess
10 Georgia Power's proposed plans," end quote.

11 As we know, GIPL could have filed this motion
12 in early February after reviewing the IRP filing;
13 it did not. Rather, GIPL waited months to assert a
14 challenge to the trade secret information contained
15 in the IRP.

16 Why is this important? Because the entire
17 premise of their argument is that public disclosure
18 of this information is, quote, unquote, "crucial,"
19 during the proceeding, but the proceeding is now
20 complete. The Commission has had a closure of
21 evidence. There are no further hearings. There is
22 no additional testimony, and the Commission has
23 voted on the IRP. They did that this morning.

24 Accordingly, this motion is moot because
25 it's -- the stated premise of the motion, to be

1 able to, quote, "freely discuss this information
2 during Georgia Power's IRP hearings," end quote,
3 has passed. Further, while GIPL's motion asserts
4 that Georgia Power failed to meet its statutory
5 burden of proving the information as trade secret,
6 GIPL has failed to explain why any of the specific
7 information they have challenged is crucial to the
8 public or why such information should be released.

9 For the most part, the information that GIPL
10 seeks to make public in this motion is technical
11 information that would mean very little to the
12 general public. I highly doubt anyone not very
13 familiar with IRP proceedings or technical utility
14 planning matters could understand things like the
15 external peak adjustment for large loads, or the
16 winter coincident demands by class of customer, or
17 the transmission marginal costs -- transmission
18 planning marginal cost, each of which is a category
19 of information included in GIPL's motion.

20 GIPL's motion also relies on circular logic
21 in attempting to establish a reason why the public
22 should be able to access this detailed and
23 technical information. At the bottom of page 3 of
24 its motion, GIPL seems to acknowledge that
25 stakeholders can obtain this information if they

1 are willing to sign confidentiality agreements, but
2 then argues that members of the public must
3 intervene to obtain that information. GIPL then
4 asserts that it is difficult for members of the
5 public to determine whether to intervene if they
6 can't have access to the trade secret information.

7 First, it is obvious that members of the
8 public do not want to fully participate in the IRP
9 hearings. They want to come down to this
10 Commission and complain that Georgia Power or this
11 Commission is not doing its job. But it is
12 painfully obvious that even those individuals don't
13 take the time to even read the IRP that is posted
14 for them publicly, so that they can be informed
15 from that process.

16 They don't want to educate themselves so that
17 they can meaningfully participate in the process.
18 They want to come down and read the talking points
19 that they have to argue that they should have
20 something different. They rightly -- rightfully
21 leave the actual participation to those
22 organizations who do intervene and who trades --
23 who signed trade -- who signed non-disclosure
24 agreements to obtain the trade secret information.

25 GIPL then argues that the trade secret

1 designations make it burdensome to identify trends
2 in time, or ask effective questions without
3 revealing trade secret information. Admittedly,
4 dealing with trade secret information in an open
5 hearing room is not the easiest. But such
6 inconveniences must be weighed against the harm it
7 would cause to release the information publicly.

8 Moreover, GIPL fails to identify any specific
9 data trends or cross-examination questions that the
10 specific information challenged in this motion
11 prevented it from identifying or asking during the
12 hearings. Making broad, generalized statements
13 does not support the claims that specific
14 information challenged in this motion should be --
15 should not be protected as trade secrets.

16 Finally, at the end of page 4, bottom of
17 page 4, we get to the real crux of the matter.
18 GIPL argues that it is unable to share trade secret
19 information with all its members or constituents to
20 further its advocacy efforts or to educate the
21 public about what is at stake in the Public
22 Commission proceedings.

23 Again, none of the technical information
24 being challenged here would even matter to the
25 general public. It is very hard to believe that

1 GIPL can't explain to their constituents or the
2 public about the importance of these proceedings
3 without release of trade secret information.
4 GIPL's motion also fails to address a very
5 important aspect of the analysis: The harm that
6 will come to Georgia Power and its customers if the
7 challenged information is released.

8 As the Commission is aware, the company has
9 disclosed more information in the 2025 IRP than it
10 ever has before. I think even GIPL would admit and
11 would agree that this is information -- the public
12 version -- there is information in the public
13 version of this IRP in 2025 that was marked as
14 trade secret in 2019, 2016, and 2022. Why I went
15 out of order, I have no idea.

16 The company takes seriously its commitment to
17 be transparent where appropriate and possible, but
18 will not willingly put itself or its customers at
19 risk of disclosing information that could be used
20 to cause economic harm.

21 Before moving on to the specific documents
22 themselves, let me address two fundamental flaws in
23 GIPL's motion. First, GIPL appears to suffer from
24 the misperception that, as a regulated monopoly,
25 Georgia Power does not have competitors. That

1 assertion is simply incorrect, as it exposes a
2 fundamental misunderstanding of the electric
3 utility landscape in the state of Georgia, as well
4 as the current state of utility competition
5 nationally.

6 Georgia Power competes against 41 EMCs and 52
7 municipalities for customer choice jobs in the
8 state of Georgia. Customer choice jobs are large
9 loads driving economic growth in Georgia, and any
10 hindrance to Georgia Power's ability to compete for
11 these jobs directly harms the company, as well as
12 its customers, who benefit from Georgia Power
13 serving these large loads.

14 Georgia Power also competes nationally to
15 bring economic development projects to the state of
16 Georgia. Your heard testimony from intervenors
17 during the IRP that, if Georgia Power can't serve
18 those loads, they're going to go to other states.
19 Losing those large loads would harm Georgia Power
20 and its customers because it drives economic growth
21 in the state of Georgia.

22 There are other competitors as well. Georgia
23 Power submits self-build projects into those RFPs,
24 as you just heard during my cross-examination of
25 GIPL's witness. Release of some of the categories

1 of information challenged by GIPL would give
2 developers insight into Georgia Power's cost
3 analysis and forecasting methodologies, which would
4 allow developers to manipulate their bids to the
5 detriment of Georgia Power and its customers.

6 This type of information has been identified
7 by FERC as information that should not be shared
8 with Southern Power, as you heard Georgia Power's
9 witnesses say earlier today. Specifically, FERC
10 requires that Georgia Power not share with Southern
11 Power information related to forecasts for fuel,
12 emissions allowances, load, and projected unit
13 operating characteristics.

14 That decision can be found in Docket No.
15 EL05-102-000, and is found at 117 FERC,
16 Paragraph 61021 at page 5, paragraph 12. Releasing
17 this information could result in RFPs selecting
18 higher winning bids, meaning that customers would
19 pay more for electricity than necessary, thus
20 harming customers. If FERC has determined that the
21 information should not be shared with Southern
22 Power because it would be anti-competitive if done
23 so, then it certainly should not be released
24 publicly.

25 Finally, even with self-build projects and

1 transmission infrastructure projects, Georgia Power
2 competitively bids out the work. Any release of
3 information that decreases the effectiveness of
4 those RFPs would harm the company, as well as
5 customers, through higher costs, as Mr. Robinson
6 testified earlier today.

7 The other fundamental flaw in GIPL's motion
8 is the claim that Georgia Power failed to establish
9 it has adequate protections to maintain the secrecy
10 of information. Our brief details the painstaking
11 process and procedure that Georgia Power undertakes
12 to ensure trade secret information is protected.

13 Those protections include, as you've heard
14 today from Mr. Bowers and Mr. Hubbert and
15 Mr. Robinson, internal employee trainings on data
16 privacy generally and specific to IRP information
17 for every IRP filing; tracking of data access to
18 ensure employees are not accessing information
19 without authorization; physical and virtual walls
20 to keep trade secret information separated
21 internally, including limiting access to certain
22 floors and areas of the Georgia Power building,
23 requiring badge swipes by authorized users to
24 obtain that information; background checks and a
25 clearance process for employees and intervenors who

1 access critical energy infrastructure --
2 infrastructure information; and password-protected
3 access to trade secret data for intervenors who
4 sign confidentiality agreements.

5 It is without question that, as required by
6 O.C.G.A. Section 10-1-761, subpart 4, the trade
7 secret information is, quote, "The subject of
8 efforts that are reasonable under the circumstances
9 to maintain secrecy."

10 Flipping very briefly to the -- you've heard
11 a lot of testimony earlier today from Georgia
12 Power's witnesses on the detailed information that
13 is contained in the exhibits. I will remind the
14 Commission that Exhibit 2A, the revenue requirement
15 information, there is information on that -- on
16 that document that has never -- never released
17 public, which is the projected AFUDC, the inflation
18 adjustments, and the cost of debt. That's never
19 released publicly.

20 Second, the revenue requirements information
21 specified in the motion could be combined with
22 publicly available expansion plan information to
23 calculate Georgia Power's production costs.
24 Exhibits 3A and 4A are seeking to disclose output
25 from Georgia Power's proprietary risk adjustment

1 model.

2 Mr. Bowers testified earlier today how
3 other -- how competitors within the state of
4 Georgia could use that information to attempt to
5 win customer choice jobs. If customer choice jobs
6 go to a utility other than Georgia Power, then
7 Georgia Power and Georgia Power's customers suffer.

8 I will finish off with -- well, I guess
9 that's my time. So I'll reserve the remaining five
10 minutes of my time for responsive comments.

11 Thank you.

12 CHAIRMAN SHAW: Thank you, Mr. Hewitson.

13 Mr. Whitfield.

14 MS. WHITFIELD: Thank you, Commissioners, and
15 I appreciate you all taking the time to hear our
16 motion and receive the evidence in this case.

17 As you are all well aware, this doesn't come
18 to the Commission very often. The last we could
19 find that the Commission in Georgia had to rule on
20 this issue was in 2007. And so in light of that --
21 I think you can probably appreciate why, it's a
22 rather labor intensive effort. But in light of
23 that, we ask that the Commission take very
24 seriously the information that we have put before
25 you, because Georgia Power is right: It discloses

1 a lot of information in every filing. It is right
2 that it has a lot of document requests that it
3 discloses. It discloses a lot of generation
4 information and financial information.

5 It also redacts an enormous amount of
6 information that keeps it out of step with other
7 utilities across the country. We did not bring to
8 you even a fraction -- a small fraction of the
9 kinds of information that Georgia Power redacts.
10 Instead, what we have brought to you are selected,
11 high level pieces of information that are
12 particularly informative for the public and from
13 which reverse engineering might be hypothetically
14 possible, or theoretically possible, but which is
15 not a reasonable assumption.

16 Mr. Hewitson has offered you some additional
17 evidence, but notably you didn't hear it from the
18 witnesses themselves. You didn't hear it as
19 evidence themselves. What they didn't say is that
20 it was likely in any way, or that they've heard of
21 this kind of harm happening, or that they have an
22 actual instance of reverse engineering. They
23 didn't say that because, as you heard from
24 Mr. Patrylak, it's not a reasonable conclusion.

25 If the Commission takes any allegation of

1 harm that Georgia Power can conceive of as the
2 definition of what a trade secret is in this venue,
3 then the definition could swallow the entire
4 proceeding, because it would be as broad as Georgia
5 Power's imagination, and Georgia Power can be very
6 creative. But that is not what we're asking of
7 you.

8 We are asking of you, are these documents --
9 the question before you is, are these documents the
10 kind of documents -- is this information the kind
11 of information for which there is a reasonable,
12 potential economic value to Georgia Power for
13 keeping it secret from other people. Not a
14 hypothetical, reverse engineering, maybe, in
15 scenarios we can't identify on the stand, but is it
16 reasonable to assume that?

17 And we urge you to look not only at Georgia
18 Power's own disclosures of this very similar
19 information in different dockets or in different
20 spaces, but we urge you to look at other -- other
21 utilities' behavior as well. Because at the end of
22 the day, like Georgia Power, we expect that all
23 utilities are operating for a reliable and
24 cost-effective system, and aren't going to be
25 disclosing information that they think will cause

1 harm.

2 In Georgia Power's motion, they argue that if
3 you vote that this information is not a trade
4 secret, they will be forced to disclose it. It is
5 scary, and it is designed to make you shirk away
6 from looking at the actual evidence and the actual
7 legal test before you.

8 But the bottom line is, the reason the
9 disclosure is required, is because the State of
10 Georgia and this Commission has a strong policy in
11 favor of an open and transparent process,
12 including, and especially, when the public funds
13 are at issue.

14 I want to be really clear about one thing:
15 Ultimately, you guys are deciding a legal test.
16 Mr. Hewitson spoke a lot about what we didn't prove
17 to you. GIPL and Southface do not need to prove
18 anything. It is Georgia Power's burden, which
19 means it is Georgia Power's responsibility, to
20 demonstrate to you why the information we've
21 identified derives economic value from not being
22 generally known to others. It is Georgia Power's
23 responsibility to identify how others can obtain
24 economic value from this information's disclosure.

25 We have provided you information as context

1 about our interest in this information. That is
2 for you to have as context to understand why and
3 what we're doing here. But for your decision about
4 whether it makes this information trade secret or
5 not, it is completely irrelevant. The question
6 before you is about the information itself.

7 So we talked about revenue requirements.
8 Revenue requirements are really important
9 information. And as you heard, the revenue
10 requirement information that we are asking for, the
11 levelized cost information that we are asking for,
12 is of a very high level and includes numerous
13 different inputs that, as you may have noticed,
14 despite me studying it with the support of some
15 consultants, there was one aspect of it that I
16 didn't appreciate, based on the disclosures
17 provided by Georgia Power. It combines a lot of
18 different factors.

19 Georgia Power's assumption of harm here is
20 that someone is going to be able to parse out all
21 of those factors to get a generic estimate at the
22 planning level that was made a year ago for when
23 they create their bids in the coming months. Quite
24 simply, it's not reasonable.

25 I understand they may have a lot of reasons

1 why they don't want to produce this information,
2 but not wanting public scrutiny is not the kind of
3 harm that is relevant to the question in front of
4 you. As a legal matter, Georgia Power not wanting
5 public scrutiny, not wanting Georgia Interfaith
6 Power & Light and Southface to take advantage of
7 the resources of additional eyes and additional
8 minds -- that may be something they want to avoid,
9 but that does not make information trade secret.
10 They have to prove to you that it has economic
11 value.

12 The large load forecasts: Mr. Hewitson said
13 that the large load forecast is the kind of
14 information nobody would really understand. I beg
15 to disagree. This information tells us and tells
16 the public how much large load Georgia Power needs
17 to get energy to serve. That is a pretty direct
18 question, and it's one we talk about all the time.

19 They will freely tell you about their very
20 large pipeline numbers. They tell you about them
21 all the time. What they don't want to talk about,
22 and what we can't talk about publicly, is how much
23 of that pipeline -- how accurate is it when they
24 say it's a tiny fraction or a small fraction of
25 that total pipeline? We can't talk about that

1 because it's not public.

2 And the idea that knowing the capacity that
3 they are planning for would stop a data center from
4 making a phone call and saying, "hey, I'm
5 interested, potentially, in coming, could you serve
6 me?" It's far-fetched. It's not how it works.
7 It's not reasonable. It could be possible in the
8 way a meteor could fall through the ceiling right
9 now.

10 And I believe that when they testified that
11 it was potential harm, that's the kind of potential
12 they were referring to. And they didn't offer you
13 any testimony otherwise.

14 Exhibit 4A that we discussed, ultimately,
15 they want to protect it for the same reasons as the
16 large load stuff, so the same arguments apply to
17 that one. The generic resource costs, this is
18 information -- we talked a lot about how
19 proprietary information can come from a consultant
20 whose business is to sell proprietary information.

21 So, of course, they want to protect it;
22 right? Of course they want to protect that -- that
23 model. But the output of the model, the outputs
24 here, those are not the kind of information that
25 Georgia Power is selling on the market. Nor, as

1 you heard from Mr. Patrylak, is it reasonable to
2 assume that a serious bidder is going to be using
3 these generic estimates, as opposed to relying on
4 their own cost of doing business, their own
5 requirement for profit, and their own best
6 estimates at the time.

7 And finally, transmission costs. I will be
8 quite candid with you and tell you this one gave me
9 a little pause at first, because when I said we
10 were very careful at picking which ones to put
11 before you, I truly mean it. We really wanted to
12 make sure it was high level stuff that would be
13 both valuable to the public and wouldn't have --
14 wouldn't come close to approaching any potential
15 harm. Transmission, I had to really study.

16 But then I realized these project estimates
17 are high level. They are planning estimates. They
18 include a lot of different information from which
19 it is not reasonable to assume reverse engineering.
20 In addition, Georgia Power is disclosing this
21 stuff. And, yes, it might be because they're
22 required to, but Georgia Power has the burden of
23 proving to you that they're keeping things like
24 their line per mile or their transmission costs --
25 or transformer costs, sorry, protected, if that's

1 their argument, that that may be what's discovered
2 here. And quite simply, they're not. You saw the
3 exhibits that show very detailed information about
4 their transmission costs. That information is out
5 there.

6 If an enterprising transmission contractor
7 wants to know what their line per mile cost is,
8 they can go find it. But at the end of the day,
9 the project estimates in this IRP are high level.
10 They are planning estimates, and they are subject
11 to change. Same with the revenue requirements.
12 They are high level.

13 So, please, Commissioners, I ask you to
14 consider the difference between the select group of
15 information before you and the long list of
16 detailed information that we recognize should
17 properly be redacted. GIPL and Southface know
18 there is a space for withholding information. We
19 know that there is a role for trade secret
20 protection to play here, and it's an important one.
21 This stuff, though, isn't that.

22 Finally, I'll note that, though this decision
23 happened this morning, as you know, these dockets
24 stay open and they are supplemented with
25 information from document requests and document

1 responses.

2 If this Commission recognizes that this
3 information is not likely to cause harm, but rather
4 it's more like the meteor, that information will be
5 supplemented in the docket for the benefit of those
6 checking this docket in the future, for the benefit
7 of use in the next docket, and in the next three
8 years, and so on in the future. So we can look
9 back and say, how well did they do when making
10 their assumptions? How well did we do when
11 criticizing them?

12 When this information is redacted 30 days
13 from today, we destroy it. We are required to, and
14 we no longer have access to that information. It
15 is important. I understand why they don't want to
16 disclose it, but the reason of not disclosing it to
17 avoid public scrutiny is not one of the legal
18 sufficient reasons that you can take into account
19 when determining if it isn't -- or is, or is not a
20 trade secret.

21 So with that, again, thank you. I appreciate
22 your time and your careful consideration.

23 CHAIRMAN SHAW: Thank you, Ms. Whitfield.

24 Georgia Power, you've got five minutes
25 reserved for a response.

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

2 Let me -- let me stop -- start where
3 Ms. Whitfield ended. The reason why this
4 information is protected as trade secret has
5 nothing to do with public scrutiny. The company
6 faces public scrutiny in almost every decision that
7 it makes, in every proposal that comes to this
8 Commission.

9 The company is trying to do what is best for
10 its customers in the state of Georgia with the 2025
11 IRP, as well as every other proceeding that is
12 filed with this Commission and prosecuted with the
13 Commission. Despite that, you're not going to make
14 everyone happy all of the time, and we face a
15 tremendous amount of public scrutiny. We don't shy
16 away from that because we are true to keeping the
17 customers at the center of everything that the
18 company does.

19 Talking about a couple of the pieces of
20 information that Ms. Whitfield covered. The large
21 load forecast, she said this is information that
22 the public would understand. I don't disagree with
23 that, but that's not what I said. What I said is,
24 we do provide that information through the
25 quarterly -- well, I didn't say it. The witnesses

1 said we provide that information through the
2 quarterly large load economic development reports.

3 What I said is, the challenged information
4 here is the external peak adjustments for large
5 loads. It's not the large load forecast. It's the
6 proprietary method by which Georgia Power does the
7 external adjustments to its peak forecast.

8 Mr. Bowers testified in detail about how
9 competitors could use that information to bid on
10 customer choice jobs.

11 Moving quickly to transmission costs, you
12 heard Mr. Robinson testify about the amount of
13 information that is provided related to
14 transmission planning and costs. What we are
15 trying to protect is the detailed marginal cost of
16 information.

17 Mr. Robinson clearly testified that you could
18 back calculate that information from project level
19 information. That marginal cost of information is
20 is the -- is the secret sauce, if you will, that
21 Georgia Power is protecting as trade secret. It's
22 not all the transmission costs, a lot of that --
23 look at trade secret -- or look at Appendix 3A, or
24 appendix -- Technical Appendix 3; look at the
25 information provided in the Transmission Planning

1 section of Georgia Power's IRP; look at the
2 information that's filed at FERC; look at the
3 information that's publicly available on Oasis.

4 Georgia Power reveals a tremendous amount of
5 information on transmission planning and
6 transmission costs. What we are trying to protect
7 and defend in this is a challenge to the trade
8 secret nature of the marginal cost of transmission
9 information, which could be used during the bidding
10 process for RFPs; could be used in the bidding
11 process for RFPs for building of the transmission;
12 and can be used by large load customers to
13 compete -- or to force competition between Georgia
14 and other states in terms of large load economic
15 development projects.

16 Let me end by talking a little bit about the
17 actual legal standard here that Ms. Whitfield was
18 talking about. She asked that you look at the
19 actual legal test in this case, and I think that is
20 a very important thing that we need to do here.

21 Georgia Power's witnesses explained in great
22 detail how disclosure could harm Georgia Power or
23 its customers from disclosure of this information.
24 Ms. Whitfield argued that there is no testimony or
25 evidence of actual harm or a reasonable likelihood

1 of harm, but that is not the test.

2 *O.C.G.A. Section 10-1-7761, subpart four,
3 which is as adopted by this Commission in Rule
4 515-3-1-.11, subpart 1, states: That information
5 which is not commonly known by or available to the
6 public, and which information, A, derives economic
7 value, actual or potential, from not being
8 generally known to, and not being readily
9 ascertainable by proper means by other persons who
10 can obtain economic value from its disclosure and
11 use.

12 I believe Georgia Power's witnesses have
13 established this standard and met this standard in
14 spades in this proceeding. At the end of the day,
15 for each of the items that have been challenged by
16 GIPL, Georgia Power has established and explained
17 why the information has economic value by not being
18 generally known to others; how others can obtain
19 economic value from disclosure of the information;
20 and how Georgia Power has maintained the secrecy of
21 the information.

22 GIPL has provided no compelling reason why
23 the general public should have access to this
24 information, or what they would do with it if they
25 had it. While Georgia Power values transparency,

1 as evidenced by the IRPs over the years of how much
2 information is being disclosed by Georgia Power, it
3 values the protection of its economic interests and
4 those of the economic interests of its customers
5 even more. GIPL's motion should be denied.

6 Thank you.

7 CHAIRMAN SHAW: Thank you, Mr. Hewitson.

8 Thank y'all for all your patience and time
9 today.

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

12 (No response.)

13 CHAIRMAN SHAW: Commissioners, is there
14 anyone that wishes to move the special admin or the
15 decision to a future administrative session date?

16 (No response.)

17 CHAIRMAN SHAW: All right. I'll ask the
18 court reporter at this time to make all exhibits
19 part of the record. We will convene the special
20 administrative session in -- let's see -- in seven
21 minutes at 1:40. Thank you again for all your
22 time, and this hearing is concluded.

23 (GIPL/Southface Exhibits 1-34 were admitted
24 into evidence.)

25 (Hearing concluded at 3:44 p.m.)

C E R T I F I C A T E

I Brenda P. Elwell, Certified Court Reporter,
do hereby certify that the foregoing transcript is
an accurate record of the proceedings had in the
above-entitled matter at the time and place therein
set forth.



Brenda P. Elwell, RPR, CCR, B-2023

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

GIPL/Southface

1-34

07/15/25

In Re:	)	
	)	
Georgia Power Company's	)	Docket No. 56002
2025 Integrated Resource Plan	)	
	)	
And	)	
	)	
Georgia Power Company's 2025	)	Docket No. 56003
Application for the Certification,	)	
Decertification, and Amended	)	
Demand-Side Management Plan	)	

EXHIBIT INDEX

FOR

HEARING ON GIPL AND SOUTHFACE'S MOTION
CHALLENGING GEORGIA POWER'S TRADE SECRET ASSERTIONS

Exhibit	Description
1-A	Letter from SELC to Troutman Pepper Locke (May 8, 2025)
1-B	Email Correspondence Between SELC and Troutman Pepper Locke (May 8, 2025)
2-A	2025 IRP Financial Review PUBLIC DISCLOSURE, from Technical Appendix Vol. 2 of Georgia Power Company's 2025 IRP Main Document Filing (Dkt. 56002)
2-B	2025 IRP Trade Secret Assertion Affidavit Vol. 2 Executed, from Technical Appendix Vol. 2 of Georgia Power Company's 2025 IRP Main Document (Docket 56002)
2-C	Georgia Power Response to Staff Data Request STF-LA-1-7, Docket 56002
2-D	Dominion Energy Virginia 2024 IRP, Table 5.1.2, Table 5.2.2, and Figure 5.3.1 (pp. 56, 66, 69)
2-E	Dominion Energy South Carolina IRP 2025 Update, Table 20 and Appendix H (pp. 79 and Appendix H-1)
2-F	Santee Cooper 2024 IRP Update, Table 4–5 and Table D–1 (pp. 11, 12, and 86)

Exhibit	Description
2-G	Duke Energy 2023 Carolinas Resource Plan, Table 2, Figures 3–5, 3–6, 3–7, Table C58, and Table C–63 (Executive Summary pp. 17, Chapter 3 pp. 10,12,14, and Appendix C pp. 86, 91)
2-H	LG&E and KU 2024 Joint IRP Volume I, Table 9–1 (pp. 9–1)
2-I	Indiana Michigan Power 2024 Indiana IRP, Table 55 (pp. 189)
2-J	TVA Draft 2025 IRP, Table 4–8 (Ch. 4, pp. 36)
3-A	Table 7.2.1: Budget 2025 External Peak Adjustments for Large Loads, from Budget 2025 Load and Energy Forecast 2025 to 2044, in Technical Appendix Volume 1 of Georgia Power Company’s 2025 IRP Main Document (Docket 56002)
3-B	2025 IRP TS Assertion Affidavit Vol. 1 Executed, from Technical Appendix Volume 1 of Georgia Power Company’s 2025 IRP Main Document (Docket 56002)
3-C	Dominion Energy Virginia 2024 IRP, Figure 2.1.7 (pp. 14) and Dominion Energy Virginia 2024 IRP Supplement, Figure 2.1.1 (pp. 2)
3-D	Santee Cooper 2024 IRP Update, Figure 3, Figure 8, and Table 6 (pp. 3, 27, and 28)
3-E	Duke Energy 2023 Carolinas Resource Plan Appendix D, Table D–11, Table D–15, and Table D–16 (pp. 15 and 19)
3-F	LG&E and KU 2024 Joint IRP Volume I, Table 5–2 and Figure 5–8 (pp. 5–13–17)
3-G	Indiana Michigan Power 2024 Indiana IRP Appendix Volume 4, Considerations for New Hyperscaler Loads (pp. 26)
4-A	Attachment 6.0-2: Winter Coincident Demand with Adjustments (MW), from Budget 2025 Load and Energy Forecast 2025 to 2044, in Technical Appendix Volume 1 of Georgia Power Company’s 2025 IRP Main Document (Dkt. 56002)
4-B	2025 IRP TS Assertion Affidavit Vol. 1 Executed, from Technical Appendix Vol. 1 of Georgia Power Company’s 2025 IRP Main Document (Docket 56002)
5-A	Georgia Power Response to Direct Hearing Request HR 1-2, requested by Georgia Interfaith Power & Light and Southface Energy Institute (Docket 56002)
5-B	Georgia Power’s Basis for the Assertion that the Information Submitted is a Trade Secret for Direct Hearing Request HR 1-2 (Docket 56002)
6-A	Table 5: B2025 Technology Cost and Performance Summary, from 2025 IRP Resource Mix Study, in Technical Appendix Volume 2 of Georgia Power Company’s 2025 IRP Main Document Filing (Docket 56002)
6-B	2025 IRP TS Assertion Affidavit Vol 2 Executed, from Technical Appendix Vol. 2 of Georgia Power Company’s 2025 IRP Main Document Filing (Docket 56002)
6-C	LG&E and KU 2024 Joint IRP Volume I, Table 6–4 (pp. 6-5)
6-D	Santee Cooper 2024 IRP Update, Table 13 and Table 14 (pp. 43–44)
6-E	Duke Energy 2023 Carolinas Resource Plan, Table E–1 and Table E–2 (pp. 10 and 12)
6-F	Indiana Michigan Power 2024 Indiana IRP, Table 18–30 (pp. 92, 93, 95, 96, 98–100, 102, 103, 107, and 112)
6-G	Dominion Energy Virginia 2024 IRP, Appendix 3K-1 and 3K-2
7-A	[C2] 2022-2024 System Performance, from 2025 IRP Transmission Plan, in Technical Appendix Volume 3 of Georgia Power Company’s 2025 IRP Main Document Filing (Docket 56002)

Exhibit	Description
7-B	2025 IRP TS Assertion Vol. 3 from Technical Appendix Volume 3 of Georgia Power Company's 2025 IRP Main Document Filing (Docket 56002)
8-A	Georgia Projects (Includes ITS & Savannah Projects), pp. 7-20, from 2025 IRP Transmission Plan, in Technical Appendix Volume 3 of Georgia Power Company's 2025 IRP Main Document Filing (Docket 56002)
8-B	2025 IRP TS Assertion Vol. 3 from Technical Appendix Volume 3 of Georgia Power Company's 2025 IRP Main Document Filing (Docket 56002)
8-C	Dominion Energy Virginia 2024 IRP, Appendix 2C-1 and 2C-2
8-D	Duke Energy 2023 Carolinas Resource Plan Appendix L, Table L-2 and Table L-7-8 (pp. 4-5, 26-27)
8-E	Indiana Michigan Power 2024 Indiana IRP Appendix Volume 1, Exhibit H
9	Excerpts from LG&E-KU 2024 IRP and DESC 2025 IRP Update (entered as GIPLSF-Exhibit 1 in Mar. 25, 2025 Hearing, Docket No. 56002)
10	Georgia Public Service Commission News Release: PSC to Begin 6-Month IRP Process, Georgians Encouraged to Participate (Feb. 7, 2025)
11	Excerpt from 2025 IRP Hearing Transcript, Dkt. 56002 (Mar. 25, 2025) at pp. 544-545 (No competitors for Georgia transmission.)
12	DESC, Planned Transmission Projects \$2M and above Total, 5 Year Budget (entered as GIPLSF-Exhibit 5 in Mar. 25, 2025 Hearing, Docket No. 56002)
13	Appendix C Transmission Plan Major Project Listings – Reliability Projects, 2024-2034 Collaborative Transmission Plan, Carolinas Transmission Planning Collaborative (entered as GIPLSF-Exhibit 6 in Mar. 25, 2025 Hearing, Docket No. 56002)
14	Georgia Power Company, T&D Capacity Addition Expansion Plans from 2019, 2022, and 2025 IRPs (entered as GIPLSF-Exhibit 3 in Mar. 25, 2025 Hearing, Docket No. 56002)
15	Excerpt from 2025 IRP Hearing Transcript, Dkt. 56002 (Mar. 25, 2025) at p. 503 (Generic Expansion Plan not catching site-specific aspects.)
16	Excerpt from 2025 IRP Hearing Transcript, Dkt. 56002 (Mar. 25, 2025) at p. 513 (“We look at kind of a Southern system generic type of costs to guide our resource mix studies.”)
17	Georgia Power Response to Staff Data Request STF-JKA-5-10(b), Docket No. 56002 (Generic resources “intended to be an indicative road map....”)
18	Excerpt from 2023 IRP Update Rebuttal Hearing Transcript, Docket No. 55378 (Mar. 27, 2024) at p. 2246 (“\$60 million worth of transmission. That is miniscule.”)
19	Georgia Power Response to Staff Data Request STF-GS-2-24, Docket No. 56002 (Estimated transmission costs change over time.)
20	Georgia Power Response to Staff Data Request STF-PIA-6-21, Docket Nos. 56002 and 56003 (Revenue requirements for DSM cases publicly disclosed.)
21	Georgia Power Response to Staff Data Request STF-BAI-1-1, Attachment Panel A (Docket No. 44280)
22	Georgia Power Public Disclosure Response to Staff Data Request STF-DEA-3-6, Supplemental 2-9-24, Attachment A (Docket No. 55378)

Exhibit	Description
23	Georgia Power Computation of Retail Revenue Deficiency for 12-mo. Periods Ending July 31, 2023 and Dec. 31, 2023-2025 and Computation of Earnings Available for Return for the 12 mo. Period Ending Dec. 31, 2025
24	Georgia Power Q1 2025 Large Load Economic Development Report, Docket No. 55378
25	Excerpts from Georgia Power’s 2023 IRP Rebuttal Hearing Transcript, Docket No. 55378 (Mar. 27, 2024) at pp. 732-733, 2054, 2057-58, 2150-53
26	Oglethorpe Power Corporation Form 8-K, June 4, 2025
27	Designation Study Report, Yates 8-10 – Coweta County, GA, March 12, 2024
28	Southern Company Generator Interconnection System Impact Study, April 12, 2024 – IC-1217 (470 MW, Jackson County)
29	Southern Company Generator Interconnection System Impact Study, April 12, 2024 – IC-1218 (640 MW, Lee County)
30	Southern Company Generator Interconnection System Impact Study, April 12, 2024 – IC-1219 (640 MW, Hart County)
31	USDA Environmental Assessment – LaGrange
32	East Central Georgia Reliability Assessment
33	Curriculum Vitae of GIPL-Southface Witness Rob Patrylak
34	Combined packet containing: Summary Table in support of 2A-2J (“Table 2”); Summary Table in 3A-3G (“Table 3”); Exh. STF-NHSW-6, Generic Resource Comparison, Docket 56002 (“Table 6”); and Summary Table in support of 8A-8E (“Table 8”)

May 8, 2025

VIA EMAIL (steven.hewitson@troutman.com; brandon.marzo@troutman.com;
allison.pryor@troutman.com)

Steven Hewitson, Brandon Marzo, and Allison Pryor
Troutman Pepper Locke
Bank of America Plaza
600 Peachtree St, NE, Suite 5200
Atlanta, GA 30308-2261

Counsel for Georgia Power Company

**RE: Request to Lift Trade Secret Designation on Information in Georgia Power
Company's 2025 Integrated Resource Plan**

Dear Mr. Hewitson, Mr. Marzo, and Ms. Pryor,

The Southern Environmental Law Center, on behalf of Georgia Interfaith Power & Light and Southface Energy Institute—intervenor in Georgia Power Company's 2025 Integrated Resource Plan proceeding before the Georgia Public Service Commission (Docket Nos. 56002 and 56003)—requests that Georgia Power Company promptly lift its claimed trade secret designation and disclose to the public the following information filed in the aforementioned dockets:

- Cost information in Georgia Power's "2025 IRP Financial Review" (**Exhibit A**)
- All information except the second column from the left in Georgia Power's "2025 IRP Volume 3 – Outages C2" (**Exhibit B**)
- Estimated cost amounts on pages 7-20 in Georgia Power's "2024 GA ITS Ten-Year Plan (2025-2034)" (**Exhibit C**)
- Information requested by GIPL and Southface in "HR-1-2" (megawatts by fuel type of the resources that are still in the Competitive Tier of the All-Source RFP) (**Exhibit D**)
- All information in "Table 5: B2025 Technology Cost and Performance Summary" from Georgia Power's 2025 IRP Resource Mix Study (**Exhibit E**)
- Attachment 6.0-2: Winter Coincident Demand with Adjustments MW from "Load and Energy Forecast in Tech, Appx 1" (**Exhibit F**)
- Table 7.2.1 Budget 2025 External Peak Adjustments for Large Loads from "Load and Energy Forecast" (**Exhibit G**)



Georgia Power has not met its burden to establish that the above information actually constitutes a “trade secret” as defined by the Georgia Trade Secrets Act and required by the Commission. O.C.G.A. § 10-1-761(4). When a monopoly utility such as Georgia Power files information in a proceeding before the Commission that it believes to be trade secret, it must provide the legal and factual basis for why each item claimed to be trade secret should not be disclosed to the public. Ga. Comp. R. & Regs. 515-3-1-.11(1)(c). Georgia Power has failed to establish in its Trade Secret Assertions the requisite elements for a proper trade secret claim: it has not and cannot explain why the information derives economic value from not being generally known to others, and it has failed to identify how a relevant competitor can obtain economic value from this information’s disclosure. *Id.*

Knowledge of this information relating to system performance, key assumptions, and estimated costs to billpayers of this IRP for which Georgia Power requests approval is crucial to intervenors’ and the public’s ability to adequately engage in the IRP proceedings. The inability to disclose this information in testimony, hearings, comments, and cross-examinations significantly hinders effective advocacy efforts and prevents Georgia Power customers from accurately assessing the magnitude of Georgia Power’s IRP. At the conclusion of the IRP proceedings, the Commission must determine whether approving Georgia Power’s IRP is in the best interest of the public. Ga. Comp. R. & Regs. 515-3-4-.01(2). By placing a trade secret label on crucial, high-level cost information and assumptions, Georgia Power also prevents the Commission from factoring in the public’s assessment of Georgia Power’s IRP in its calculus.

We urge Georgia Power to lift the trade secret designation on the above-listed documents to ensure a transparent and effective IRP proceeding. Please provide your response no later than **Thursday, May 15, 2025**.

Sincerely,

s/Jennifer Whitfield

Jennifer Whitfield
Bob Sherrier
Aradhana Chandra
Southern Environmental Law Center
Ten 10th Street NW, Suite 1050
Atlanta, Georgia 30309
404-521-9900

Counsel for GIPL and Southface

cc: Robert Trokey, Georgia Public Service Commission Staff (rtrokey@psc.ga.gov)
Tom Bond, Georgia Public Service Commission Staff (tbond@psc.ga.gov)

Aradhana Chandra

From: Jennifer Whitfield
Sent: Thursday, May 8, 2025 3:53 PM
To: Hewitson, Steven J.; Marzo, Brandon F.; Pryor, Allison
Cc: Aradhana Chandra; Bob Sherrier; Robert Trokey; Tom Bond
Subject: RE: Letter re Trade Secret Designations

Thanks Steve. We look forward to your response.

Best,
Jen

From: Hewitson, Steven J. <steven.hewitson@troutman.com>
Sent: Thursday, May 8, 2025 3:11 PM
To: Jennifer Whitfield <jwhitfield@selc.org>; Marzo, Brandon F. <Brandon.Marzo@troutman.com>; Pryor, Allison <Allison.Pryor@troutman.com>
Cc: Aradhana Chandra <achandra@selc.org>; Bob Sherrier <bsherrier@selc.org>; Robert Trokey <rtrokey@psc.ga.gov>; Tom Bond <tbond@psc.ga.gov>
Subject: RE: Letter re Trade Secret Designations

Jennifer –

Thanks for the letter and the opportunity to respond. Georgia Power will prepare a response for your consideration. I doubt it will be ready by May 15, but one will be provided.

-Steve

Steven J. Hewitson
Partner
troutman pepper locke
Direct: 404.885.3475 | Mobile: 404.202.7807
steven.hewitson@troutman.com

From: Jennifer Whitfield <jwhitfield@selc.org>
Sent: Thursday, May 8, 2025 1:44 PM
To: Hewitson, Steven J. <steven.hewitson@troutman.com>; Marzo, Brandon F. <Brandon.Marzo@troutman.com>; Pryor, Allison <Allison.Pryor@troutman.com>
Cc: Aradhana Chandra <achandra@selc.org>; Bob Sherrier <bsherrier@selc.org>; Robert Trokey <rtrokey@psc.ga.gov>; Tom Bond <tbond@psc.ga.gov>
Subject: Letter re Trade Secret Designations

CAUTION: This message came from outside the firm. DO NOT click links or open attachments unless you recognize the sender (look at the actual email address) and confirm the content is safe.

Steve, Brandon, and Allison,



Please find attached a letter concerning Georgia Power's trade secret designations. As reflected in the letter, we kindly request your response by next Thursday, May 15.

Best,
Jennifer

Jennifer Whitfield
Senior Attorney

Southern Environmental Law Center
10 10th St NW, Suite 1050
Atlanta, GA 30312

Office (404) 521-9900
Direct (678) 277-4821
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southernenvironment.org
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PUBLIC DISCLOSURE

Case	Sensitivity Description	Real Levelized ¢/KWH	Percent Above Base Case	Levelized ¢/KWH	Percent Above Base Case
0	Base Case (111 with Moderate Gas / Lower Carbon)	REDACTED		REDACTED	
1	111 with High Gas / Lower Carbon	REDACTED	23.3%	REDACTED	23.3%
2	111 with Moderate Gas / Higher Carbon	REDACTED	19.5%	REDACTED	19.5%
3	Low Gas / Lower Carbon	REDACTED	-14.0%	REDACTED	-14.0%
4	Moderate Gas / Lower Carbon	REDACTED	-7.6%	REDACTED	-7.6%
5	High Gas / Lower Carbon	REDACTED	11.6%	REDACTED	11.6%
6	Moderate Gas / Moderate Carbon	REDACTED	10.0%	REDACTED	10.0%
7	Moderate Gas / Higher Carbon	REDACTED	36.5%	REDACTED	36.5%
8	Emissions Limit	REDACTED	195.4%	REDACTED	195.3%
9	High Load	REDACTED	-3.5%	REDACTED	-3.3%
10	No Non-Dispatchable DSM	REDACTED	-8.2%	REDACTED	-8.1%
11	Advocates	REDACTED	-8.1%	REDACTED	-8.1%
12	Economy Energy Purchase	REDACTED	-7.4%	REDACTED	-7.4%

Note: Plan for 2026 through 2044



PUBLIC DISCLOSURE

0 Plan : Base Case (111 with Moderate Gas / Lower Carbon)

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:		Structure	Cost	After Tax Wtd. Cost
	Debt	45%	REDACTED	REDACTED
	Preferred	0%	REDACTED	REDACTED
	Equity	55%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.38%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average \$/ kWh ** 8	Real Levelized Average \$/ kWh	Real Levelized Revenue Requirements	Levelized Average \$/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

PUBLIC DISCLOSURE

1 Plan : 111 with High Gas / Lower Carbon

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:		Structure	Cost	After Tax
	Debt	45.00%	REDACTED	Wtd. Cost
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

PUBLIC DISCLOSURE

2 Plan : 111 with Moderate Gas / Higher Carbon

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:				After Tax
		Structure	Cost	Wtd. Cost
	Debt	45.00%	REDACTED	REDACTED
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

3 Plan : Low Gas / Lower Carbon**Item**

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:				After Tax
		Structure	Cost	Wtd. Cost
	Debt	45.00%	REDACTED	REDACTED
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$'000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

4 Plan : Moderate Gas / Lower Carbon

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:				After Tax
		Structure	Cost	Wtd. Cost
	Debt	45.00%	REDACTED	REDACTED
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

5 Plan : High Gas / Lower Carbon

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:		Structure	Cost	After Tax
	Debt	45.00%	REDACTED	Wtd. Cost
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh **8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

6 Plan : Moderate Gas / Moderate Carbon

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:				After Tax
		Structure	Cost	Wtd. Cost
	Debt	45.00%	REDACTED	REDACTED
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

PUBLIC DISCLOSURE

7 Plan : Moderate Gas / Higher Carbon

Item

1. General rate of inflation:	REDACTED				
2. Monthly AFUDC rate for plan:	REDACTED				
3. Cost of capital rate:					
	Debt	Structure	Cost	After Tax	
		45.00%	REDACTED	Wtd. Cost	REDACTED
	Preferred	0.00%	REDACTED		REDACTED
	Equity	55.00%	REDACTED		REDACTED
4. After Tax Discount rate used in present worth calculation:					REDACTED
5. Tax rate used in plan:	25.39%				

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

8 Plan : Emissions Limit

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:		Structure	Cost	After Tax
	Debt	45.00%	REDACTED	Wtd. Cost
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

PUBLIC DISCLOSURE

9 Plan : High Load

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:		Structure	Cost	After Tax
	Debt	45.00%	REDACTED	Wtd. Cost
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

10 Plan : No Non-Dispatchable DSM**Item**

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:				After Tax
		Structure	Cost	Wtd. Cost
	Debt	45.00%	REDACTED	REDACTED
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

11 Plan : Advocates

Item

1. General rate of inflation:	REDACTED			
2. Monthly AFUDC rate for plan:	REDACTED			
3. Cost of capital rate:		Structure	Cost	After Tax
	Debt	45.00%	REDACTED	Wtd. Cost
	Preferred	0.00%	REDACTED	REDACTED
	Equity	55.00%	REDACTED	REDACTED
4. After Tax Discount rate used in present worth calculation:				REDACTED
5. Tax rate used in plan:	25.39%			

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

12 Plan : Economy Energy Purchase**Item**

1. General rate of inflation:	REDACTED				
2. Monthly AFUDC rate for plan:	REDACTED				
3. Cost of capital rate:				After Tax	
		Structure	Cost	Wtd. Cost	
	Debt	45.00%	REDACTED	REDACTED	
	Preferred	0.00%	REDACTED	REDACTED	
	Equity	55.00%	REDACTED	REDACTED	
4. After Tax Discount rate used in present worth calculation:				REDACTED	
5. Tax rate used in plan:	25.39%				

Present Worth Calculations of Revenue Requirements

Year	Total Annual Revenue Requirement **7 (\$000's)	Total Annual GWH	Nominal Average ¢/ kWh ** 8	Real Levelized Average ¢/ kWh	Real Levelized Revenue Requirements	Levelized Average ¢/ kWh	Levelized Revenue Requirements
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED			REDACTED		REDACTED

6. Present worth of revenue requirements for the plan

** 7. Nominal revenue requirements by year

** 8. Average system rates per kWh by year

9. Overall assessment of business and financial risks associated with the plan, including the identification of appropriate financial measures.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

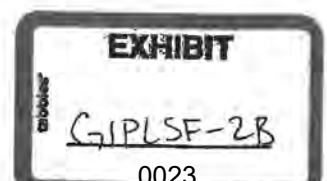
**GEORGIA POWER COMPANY
DOCKET NO. 56002**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2025 Integrated Resource Plan ("2025 IRP"), filed in Docket No. 56002, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 2, which contains certain information regarding the company's financial data, proprietary planning processes, technology screening assumptions, technology and resource cost information, economic analyses, environmental compliance costs, including projected and current cost estimates for coal combustion residual asset retirement obligation ("CCR ARO") ash pond closure and landfill projects, Critical Energy Infrastructure Information ("CEII") related to the Company's blackstart facilities, and other data of the Company (collectively, the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the trade secret portions of the Information contain competitively sensitive cost information related to available technology options, processes and data used by Georgia Power in analyzing resource addition schedules, financial data used in the Company's forecasting, and other confidential details. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. With this competitive advantage, Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers. The Information also includes sensitive details concerning Georgia Power's electric system infrastructure that must be protected from public disclosure in the interests of system security and reliability. Such portions of the Information contain CEII as defined by the Code of Federal Regulations Section 388.113.

The trade secret portions of the Information contained herein also include details concerning Georgia Power's projected environmental capital investments, cost data, and analyses, all of which have economic value that could be inappropriately leveraged by competitors, vendors, or other persons. Specifically, the trade secret portions of the Information contain competitively sensitive details on the site specific and CCR unit specific costs the Company is expected to incur to close its ash ponds and landfills as well as the timing. Publicly disclosing these costs would allow bidders and vendors to tailor proposals according to the Company's expected costs, setting an artificial floor on bidding to the detriment and harm of the Company and its customers. Disclosure of the trade secret portions of the Information could prevent the Company from adequately soliciting and obtaining the best cost estimates for future consulting work and harm the Company's efforts to



obtain optimal pricing in current or future negotiations. In addition, the Company's competitors are not generally required to disclose similar information, and to require the Company to do so would put it at an economic disadvantage.

Additionally, certain trade secret portions of the Information contain proprietary cost data and analysis prepared on the Company's behalf by outside consultants. These studies were prepared by paid consultants of the Company at a significant cost and thus derive economic value from not being generally known. To allow competitors to access information related to and contained in these studies would economically harm the Company in that competitors would be able to benefit from the information and analysis contained in the studies without similarly being required to expend similar resources for the analysis and intelligence.

The trade secret portions of the Information are subject to substantial procedures to maintain their secrecy. Only select Georgia Power and Southern Company personnel are granted access to the trade secret portions of the Information. Those personnel receive access only on a "need to know" basis. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 2 of the Company's 2025 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).

Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 27 day of January, 2025.

Notary Public

My Commission expires:



Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

STF-LA-1-7

Question:

Refer to the tables on pages 2 through 14 of 14.

- a. For each scenario shown in pages 2 through 14 of 14 for each of the amounts shown in the column "Total Annual Revenue Requirement" show in detail how such amounts were calculated, including details for each rate base component, each operating income component, the return component, income taxes, and how net operating incomes were grossed-up for the revenue requirement amounts. Include Excel files with formulas intact.
- b. Explain what the Real Levelized Average rates represent.
- c. Why do the Real Levelized Average rates vary from year to year?
- d. What are the "Levelized Revenue Requirements"?
- e. Why do the "Levelized Revenue Requirements" vary from year to year?
- f. For each scenario shown in pages 2 through 14 of 14 what are the projected annual revenue requirements without any levelization? Provide calculations in Excel.
- g. Was any discount rate used on the tables on pages 2 through 14 of 14 for any of the columns? If so, identify what discount rate(s) was/(were) used and provide the non-discounted amounts to which the discount rate(s) were applied. Also, show in Excel with formulas intact, how the discount rates were applied.
- h. Refer to the tables on pages 2 through 14 of 14. Which columns represent net present values?
- i. Refer to the tables on pages 2 through 14 of 14. Which columns represent nominal non-discounted dollars?
- j. Refer to the tables on pages 2 through 14 of 14. Do any of the amounts in the "Total Annual Revenue Requirement" columns for years 2026, 2027 and 2028 represent the Company's current best estimates of the rate case revenue requirement increases for any of the scenarios? If not, explain fully why not. If so, which specific items on pages 2 through 14 represent the Company's current best estimates of the rate case revenue requirement increases for years 2026, 2027 and 2028? Explain fully.

Georgia Power Company
Docket Nos. 56002 & 56003
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STF-LA Data Request Set No. 1

k. For the 2025 rate case expected to follow the 2025 IRP, does the Company expect that it will be requesting levelized revenue amounts that are based on amounts for any years beyond 2026-2028? If so, please explain.

Response:

- a. Please see STF-LA-1-1 Attachment TRADE SECRET for the full calculation of each scenario. Please note, no scenarios represent the Company's full rate base and thus do not represent a total revenue requirement. The costs included for the current generation are the variable costs only, which are then added to the full cost of any additional generation needed as the system grows.
- b. The Real Levelized Averages represent the average cents per kWh if the load were to grow at the rate of inflation.
- c. The Real Levelized rates vary from year to year because they only measure the current year and remaining years levelized at the rate of inflation (e.g., 2026 calculates levelized 2026 through 2044, 2027 calculates levelized 2027 through 2044).
- d. The Levelized Revenue Requirements represent the average cents per kWh if the load were to grow at the kWh growth projected for each scenario.
- e. The Levelized Revenue Requirements vary from year to year because they only measure the current year and remaining years (e.g., 2026 calculates levelized 2026 through 2044, 2027 calculates levelized 2027 through 2044).
- f. Please see STF-LA-1-1 Attachment TRADE SECRET column L of each scenario for the revenue requirements without levelization.
- g. Please see STF-LA-1-1 Attachment TRADE SECRET cell P12 in each scenario page for the after-tax discount rate used to calculate Net Present Values in columns L,M,P and R on row 40. All values and calculations are provided in the attachment.
- h. Please see STF-LA-1-1 Attachment TRADE SECRET. Row 40 shows the NPV for each scenario.
- i. Please see STF-LA-1-1 Attachment TRADE SECRET column L. Rows 20-38 show the nominal revenue requirements.
- j. No, none of the scenarios represent the Company's base rate case revenue requirements. The Company has not yet prepared its 2025 base rate case budget, which is required to be

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-LA Data Request Set No. 1

filed by July 1, 2025. Information about the future base rate case will be available once the rate case has been prepared and filed. Please note, no scenarios represent the Company's full rate base and thus do not represent a total revenue requirement. The costs included for the current generation are the variable costs only which are then added to the full cost of any additional generation needed as the system grows.

k. The Company has not yet prepared its 2025 base rate case budget. Information about the future base rate case will be available once the rate case has been prepared and filed.

DOMINION VIRGINIA 2024 IRP*

Table 5.1.2: Modeling Results Summary

	REC RPS Only with EPA	REC RPS Only without EPA	VCTA with EPA	VCTA without EPA
Net Present Value ("NPV") Total (\$B)	\$100.2	\$93.7	\$102.9	\$97.0
Approximate CO₂ Emissions from Company in 2029 (Metric Tons)	19.6 M	25.0 M	19.3 M	24.6 M
Solar (MW)	11,932	11,932	12,210	12,210
Wind (MW)	3,460	3,460	3,460	3,460
Storage (MW)	4,577	4,577	4,100	4,100
Nuclear (MW)	1,340	1,340	1,340	1,340
Natural Gas Fired (MW)	5,934	5,934	5,934	5,934
Retirements (MW)	-	-	-	-

Table 5.2.2: NPV results for the Primary Portfolios

(\$B)	REC RPS Only with EPA	REC RPS Only without EPA	VCTA With EPA	VCTA Without EPA
Total System Costs	78.6	72.1	81.3	75.4
Grid Plan (Net of Benefits)	(1.6)	(1.6)	(1.6)	(1.6)
SUP	0.9	0.9	0.9	0.9
Transmission	22.4	22.4	22.4	22.4
Total Plan NPV	100.2	93.7	102.9	97.0
Portfolio Delta vs. REC RPS Only with EPA	-	-	2.8	3.3

Notes: As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments. All costs are estimates and will vary based on the actual generation, transmission, and distribution infrastructure developed to meet customer needs. (1) Total system costs include the results from Figures 5.1.3 through 5.1.6 plus approved, proposed, future, and generic DSM, as applicable; costs related to environmental laws and regulations; renewable energy integration costs; and REC banking as discussed in Appendices 2E, 3D, 5A, and 5B. (2) All NPVs are calculated with a 6.52% discount rate. (3) Numbers may not add due to rounding.

Figure 5.3.1: 2024 Plan Sensitivities on Load Forecast

	PJM Load Forecast (VCTA with EPA Portfolio)	PJM High Load Forecast	PJM Low Load Forecast	Company Load Forecast
NPV Total (\$B)	102.9	123.0	\$3.1	104.3
Approximate CO₂ Emissions from Company in 2029 (Metric Tons)	19.3	31.8	16.8	19.9
Solar (MW)	12,210	12,210	12,210	12,210
Wind (MW)	3,460	3,460	60	3,460
Storage (MW)	4,100	4,000	4,100	4,200
Nuclear (MW)	1,340	1,340	-	1,072
Natural Gas Fired (MW)	5,934	5,934	4,666	5,934
Retirements (MW)	-	-	-	-

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

EXHIBIT

tabbles

GIPLSF-2D



**Dominion
Energy®**

**Virginia Electric and Power
Company's Report of Its
2024 Integrated Resource Plan**

**Before the Virginia State
Corporation Commission and
North Carolina Utilities
Commission**

**Case No. PUR-2024-00184
Docket No. E-100, Sub 204**

Filed: October 15, 2024

Table 5.1.2: Modeling Results Summary

	REC RPS Only with EPA	REC RPS Only without EPA	VCEA with EPA	VCEA without EPA
Net Present Value ("NPV") Total (\$B)	\$100.2	\$93.7	\$102.9	\$97.0
Approximate CO₂ Emissions from Company in 2029 (Metric Tons)	19.6 M	25.0 M	19.3 M	24.6 M
Solar (MW)	11,932	11,932	12,210	12,210
Wind (MW)	3,460	3,460	3,460	3,460
Storage (MW)	4,577	4,577	4,100	4,100
Nuclear (MW)	1,340	1,340	1,340	1,340
Natural Gas Fired (MW)	5,934	5,934	5,934	5,934
Retirements (MW)	-	-	-	-

5.2.2 NPV of the Primary Portfolios

Dominion Energy evaluated the four primary Portfolios to compare the NPV²⁴ utility costs over the Planning Period. Table 5.2.2 presents these NPV results on the “Total System Costs” line, as well as the estimated NPV of proposed investments in the Company’s transmission and distribution systems, broken down by specific line item.

Table 5.2.2: NPV results for the Primary Portfolios

(\$B)	REC RPS Only with EPA	REC RPS Only without EPA	VCEA With EPA	VCEA Without EPA
Total System Costs	78.6	72.1	81.3	75.4
Grid Plan (Net of Benefits)	(1.6)	(1.6)	(1.6)	(1.6)
SUP	0.9	0.9	0.9	0.9
Transmission	22.4	22.4	22.4	22.4
Total Plan NPV	100.2	93.7	102.9	97.0
Portfolio Delta vs. REC RPS Only with EPA	-	-	2.8	3.3

Notes: As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments. All costs are estimates and will vary based on the actual generation, transmission, and distribution infrastructure developed to meet customer needs. (1) Total system costs include the results from Figures 5.1.3 through 5.1.6 plus approved, proposed, future, and generic DSM, as applicable; costs related to environmental laws and regulations; renewable energy integration costs; and REC banking as discussed in Appendices 2E, 3D, 5A, and 5B. (2) All NPVs are calculated with a 6.52% discount rate. (3) Numbers may not add due to rounding.

5.2.3 Hydrogen Blending

As mentioned in Chapters 3.6.1 and 3.7, the Company continues to evaluate the blending of hydrogen at its existing and future natural gas-fired power stations. In order to demonstrate the impact hydrogen blending could have on CO₂ intensity, the Company conducted a high-level evaluation of the impacts of hydrogen blending on each primary Portfolio. This evaluation assumes that the Company could begin blending 10% hydrogen at capable natural gas-fired power stations beginning in 2028, and increasing to 30% by 2032. As seen in Figures 5.2.3.1 through 5.2.3.4 below, blending of hydrogen would have an immediate positive impact on carbon intensity levels which would continue throughout the Planning Period.

²⁴ NPV is a way to show how much an investment is worth throughout its lifetime and shown in today’s dollars.

5.3 Sensitivity Analyses

The Company conducted several sensitivity analyses for this 2024 IRP to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements.

First, the Company conducted sensitivities using different load forecasts. As discussed above, all Portfolios utilized the 2024 PJM Derived Load Forecast. The Company used the same general methodology to create the high/low sensitivities as it did in the PJM Derived Load Forecast. The differences are that the high/low sensitivities use a variation on the Data Center Load Forecast and the EE adjustment to the load forecast. In the high load forecast sensitivity, the Company modeled that the Data Center Load Forecast would be 5% higher in the first year of the forecast growing in a linear fashion to be 20% higher than the PJM Derived Load Forecast by 2039. Additionally, the Company modeled that EE savings would be half of the forecasted amounts. This resulted in a high load forecast sensitivity which starts out 1.5% higher than the PJM Derived Load Forecast in the first year, moving to 11.5% higher by 2039.

Stakeholder Process Highlight: The Company received feedback from stakeholders regarding running a sensitivity on the load forecast that includes higher and lower ranges for the load forecast. The Company included this sensitivity as described in this section.

The low load forecast sensitivity used the same general methodology as in the high load forecast sensitivity, with the exception that the Data Center Load Forecast was reduced by 5% in the first year proceeding in a linear fashion to a 20% reduction. EE savings were increased by 50%. This resulted in a low load forecast sensitivity which was symmetrical to the high load forecast sensitivity, being 1.5% lower than the PJM Derived Load Forecast in the first year, moving to 11.5% lower by 2039. The Company also ran a sensitivity using the 2024 Company Load Forecast. Figure 5.3.1 shows the results of these sensitivities.

Figure 5.3.1: 2024 Plan Sensitivities on Load Forecast

	PJM Load Forecast (VCEA with EPA Portfolio)	PJM High Load Forecast	PJM Low Load Forecast	Company Load Forecast
NPV Total (\$B)	102.9	123.0	83.1	104.3
Approximate CO ₂ Emissions from Company in 2039 (Metric Tons)	19.3	31.8	16.8	19.9
Solar (MW)	12,210	12,210	12,210	12,210
Wind (MW)	3,460	3,460	60	3,460
Storage (MW)	4,100	4,000	4,100	4,200
Nuclear (MW)	1,340	1,340	-	1,072
Natural Gas Fired (MW)	5,934	5,934	4,666	5,934
Retirements (MW)	-	-	-	-

DOMINION SOUTH CAROLINA 2025 IRP UPDATE*

Appendix H: Levelized Cost and Fuel Cost Comparison for the Twenty-One

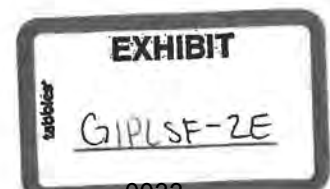
Cases

Market Scenario	Build Plan	Fuel (\$000)	CO2 (\$000)	LNPV (\$000)
Reference	Updated 2023 Reference Build Plan	\$697,327	\$160,100	\$2,629,814
Reference	2025 Reference Build Plan	\$732,830	\$168,022	\$2,393,372
Reference	High Fossil Fuel Prices Build Plan	\$723,325	\$167,487	\$2,406,974
Reference	Zero Carbon Cost Build Plan	\$760,010	\$176,336	\$2,399,077
Reference	Alternate Reference Build Plan	\$718,160	\$164,804	\$2,303,000
High Fossil Fuel Prices	Updated 2023 Reference Build Plan	\$918,925	\$160,016	\$2,852,047
High Fossil Fuel Prices	2025 Reference Build Plan	\$962,782	\$167,805	\$2,624,528
High Fossil Fuel Prices	High Fossil Fuel Prices Build Plan	\$949,043	\$167,207	\$2,633,665
High Fossil Fuel Prices	Zero Carbon Cost Build Plan	\$999,477	\$176,125	\$2,639,756
High Fossil Fuel Prices	Alternate Reference Build Plan	\$931,848	\$166,833	\$2,518,609
Zero Carbon Cost	Updated 2023 Reference Build Plan	\$622,174	\$0	\$2,392,817
Zero Carbon Cost	2025 Reference Build Plan	\$653,891	\$0	\$2,144,896
Zero Carbon Cost	High Fossil Fuel Prices Build Plan	\$644,794	\$0	\$2,159,310
Zero Carbon Cost	Zero Carbon Cost Build Plan	\$678,469	\$0	\$2,140,005
Zero Carbon Cost	Alternate Reference Build Plan	\$641,286	\$0	\$2,060,440
Sensitivity Case	Electrification Build Plan	\$791,318	\$0	\$2,660,551
Sensitivity Case	Energy Conservation Build Plan	\$882,688	\$149,574	\$2,413,999
Sensitivity Case	Aggressive Regulation Build Plan	\$1,094,795	\$395,409	\$3,410,745
Sensitivity Case	High DSM Build Plan	\$740,579	\$169,377	\$2,376,068
Sensitivity Case	Low DSM Build Plan	\$735,549	\$166,982	\$2,396,449
Supplemental Case	85% CO2 Reduction Plan	\$517,176	\$55,621	\$3,527,990

Table 20. Levelized Cost Comparison of the Core Build Plans (30-Year LNPV in Thousands of Dollars)

Core Build Plans 30 Yr Level NPV (\$M)			
Build Plans	Market Scenario		
	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Updated 2023 Reference Build Plan	2,630	2,653	2,140
2025 Reference Build Plan	2,393	2,625	2,145
High Fossil Fuel Prices Build Plan	2,407	2,634	2,159
Zero Carbon Cost Build Plan	2,399	2,640	2,140
Alternate Reference Build Plan	2,303	2,519	2,060

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.





**INTEGRATED RESOURCE PLAN
2025 UPDATE**

Dominion Energy South Carolina, Inc.

March 31, 2025

Appendix H: Levelized Cost and Fuel Cost Comparison for the Twenty-One Cases

Market Scenario	Build Plan	Fuel (\$000)	CO2 (\$000)	LNPV (\$000)
Reference	Updated 2023 Reference Build Plan	\$697,327	\$160,100	\$2,629,814
Reference	2025 Reference Build Plan	\$732,830	\$168,022	\$2,393,372
Reference	High Fossil Fuel Prices Build Plan	\$723,325	\$167,487	\$2,406,974
Reference	Zero Carbon Cost Build Plan	\$760,010	\$176,336	\$2,399,077
Reference	Alternate Reference Build Plan	\$718,160	\$164,804	\$2,303,000
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High Fossil Fuel Prices	2025 Reference Build Plan	\$962,782	\$167,805	\$2,624,528
High Fossil Fuel Prices	High Fossil Fuel Prices Build Plan	\$949,043	\$167,207	\$2,633,665
High Fossil Fuel Prices	Zero Carbon Cost Build Plan	\$999,477	\$176,125	\$2,639,756
High Fossil Fuel Prices	Alternate Reference Build Plan	\$931,848	\$166,833	\$2,518,609
Zero Carbon Cost	Updated 2023 Reference Build Plan	\$622,174	\$0	\$2,392,817
Zero Carbon Cost	2025 Reference Build Plan	\$653,891	\$0	\$2,144,896
Zero Carbon Cost	High Fossil Fuel Prices Build Plan	\$644,794	\$0	\$2,159,310
Zero Carbon Cost	Zero Carbon Cost Build Plan	\$678,469	\$0	\$2,140,005
Zero Carbon Cost	Alternate Reference Build Plan	\$641,286	\$0	\$2,060,440
Sensitivity Case	Electrification Build Plan	\$791,318	\$0	\$2,660,551
Sensitivity Case	Energy Conservation Build Plan	\$882,688	\$149,574	\$2,413,999
Sensitivity Case	Aggressive Regulation Build Plan	\$1,094,795	\$395,409	\$3,410,745
Sensitivity Case	High DSM Build Plan	\$740,579	\$169,377	\$2,376,068
Sensitivity Case	Low DSM Build Plan	\$735,549	\$166,982	\$2,396,449
Supplemental Case	85% CO2 Reduction Plan	\$517,176	\$55,621	\$3,527,990

Table 20. Levelized Cost Comparison of the Core Build Plans (30-Year LNPV in Thousands of Dollars)

Core Build Plans 30 Yr Level NPV (\$M)			
Build Plans	Market Scenario		
	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Updated 2023 Reference Build Plan	2,630	2,852	2,393
2025 Reference Build Plan	2,393	2,625	2,145
High Fossil Fuel Prices Build Plan	2,407	2,634	2,159
Zero Carbon Cost Build Plan	2,399	2,640	2,140
Alternate Reference Build Plan	2,303	2,519	2,060

The LNPV cost rankings of the Core Build Plans are generally consistent among the Core Market Scenarios. The Alternate Reference Build Plan is the most cost-effective Core Build Plan in all cases. The 2025 Reference Build Plan, the High Fossil Fuel Cost Build Plan, and the Zero Carbon Cost Build Plan are either the second or third most cost-effective Core Build Plans in all cases. The Updated 2023 Reference Build Plan is consistently the highest cost plan across all Core Market Scenarios.

[Table begins on following page]

SANTEE COOPER 2024 IRP UPDATE*

Table 4. Comparison of NPV Power Costs (\$B)

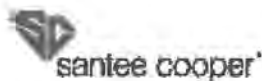
Portfolios	NPV Power Costs
2024 Portfolio Update	\$29.3
2024 Portfolio with PPAs	\$29.2
GHG Rule Portfolio	\$35.7
<u>Difference to 2024 Portfolio Update</u>	
2024 Portfolio with PPAs	(\$0.1)
GHG Rule Portfolio	\$6.5

Table 5. Fuel Price Sensitivity Results

Supplemental Portfolios	NPV Power Costs (\$B)			Range of Uncertainty
	Reference Case	Low Fuel Price	High Fuel Price	
2024 Portfolio Update	\$29.3	\$27.6	\$33.3	\$5.7
2024 Portfolio with PPAs	\$29.2	\$27.5	\$33.2	\$5.7
GHG Rule Portfolio	\$35.7	\$33.4	\$42.5	\$9.1

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.





APPENDIX D: NPV POWER COST SUMMARY

Table D-1: Net Present Value Power Costs by Portfolio Across Sensitivities (\$B; 2023\$)

Portfolio	Sensitivity Case	Study Period (2024-52)	20 Years (2031-50)
2023 Preferred Portfolio (Reoptimized)	Reference	\$29.3	\$21.0
2024 Portfolio Update	Reference	\$29.3	\$21.0
2024 Portfolio with PPAs	Reference	\$29.2	\$21.0
GHG Rule Portfolio	Reference	\$35.7	\$27.2
2024 Portfolio Update	Low Fuel	\$27.6	\$19.6
2024 Portfolio with PPAs	Low Fuel	\$27.5	\$19.6
GHG Rule Portfolio	Low Fuel	\$33.4	\$25.2
2024 Portfolio Update	High Fuel	\$33.3	\$24.1
2024 Portfolio with PPAs	High Fuel	\$33.2	\$24.0
GHG Rule Portfolio	High Fuel	\$42.5	\$32.8
2024 Portfolio Update	Med CO2	\$36.6	\$26.8
2024 Portfolio with PPAs	Med CO2	\$36.6	\$26.8
GHG Rule Portfolio	Med CO2	\$40.8	\$30.9
2024 Portfolio Update	High CO2	\$49.6	\$36.9
2024 Portfolio with PPAs	High CO2	\$49.6	\$36.9
GHG Rule Portfolio	High CO2	\$50.5	\$37.9
2024 Portfolio Update	High Load	\$38.2	\$28.5
2024 Portfolio with PPAs	High Load	\$38.2	\$28.5
GHG Rule Portfolio	High Load	\$46.6	\$36.6
2024 Portfolio Update	Low Load	\$21.8	\$14.8
2024 Portfolio with PPAs	Low Load	\$21.8	\$14.8
GHG Rule Portfolio	Low Load	\$25.6	\$18.5
2024 Portfolio with Self Build NGCC	Reference	\$29.3	\$21.1



Santee Cooper

Integrated Resource Plan

2024 Update



Executive Summary

- The 2024 Portfolio Update is essentially identical to the 2023 Preferred Portfolio Re-Optimized. Hence, while the portfolio metrics discussed from this point refer to the 2024 Portfolio Update, it is important to recognize that results would be essentially the same for the 2023 Preferred Portfolio Re-Optimized.
- The GHG Rule Portfolio would result in significant resource additions that are needed upon retirement of Cross by 2032. Given the scale of the Cross Generating Station (2,330 MW), there is significant uncertainty and risk as to whether Santee Cooper can practically implement the generation resources, necessary fuel delivery infrastructure, and modifications to its transmission system to meet the schedule mandated by the current EPA GHG Rule.

Net present value ("NPV") Power Costs presented in Table 4 summarize the incremental power supply costs projected to result from the implementation of each Portfolio. Costs are presented in NPV 2024 dollars, computed over the 2024 through 2052 study period ("Study Period"), and represent only incremental costs that vary between alternative resource plans.

Table 4. Comparison of NPV Power Costs (\$B)

Portfolios	NPV Power Costs
2024 Portfolio Update	\$29.3
2024 Portfolio with PPAs	\$29.2
GHG Rule Portfolio	\$35.7
<u>Difference to 2024 Portfolio Update</u>	
2024 Portfolio with PPAs	(\$0.1)
GHG Rule Portfolio	\$6.5

Results indicate that portfolios that rely on new NGCT builds in 2031 or limits NGCT builds by offering PPA options in the 2030s are projected to have similar costs. Decisions on which of these portfolio approaches are more appropriate for Santee Cooper will instead rely on business decisions regarding managing implementation and financial risk, maintaining flexibility for future resource additions as load projections change, transmission import capability, and additional information regarding PPA market depth and pricing, among others.

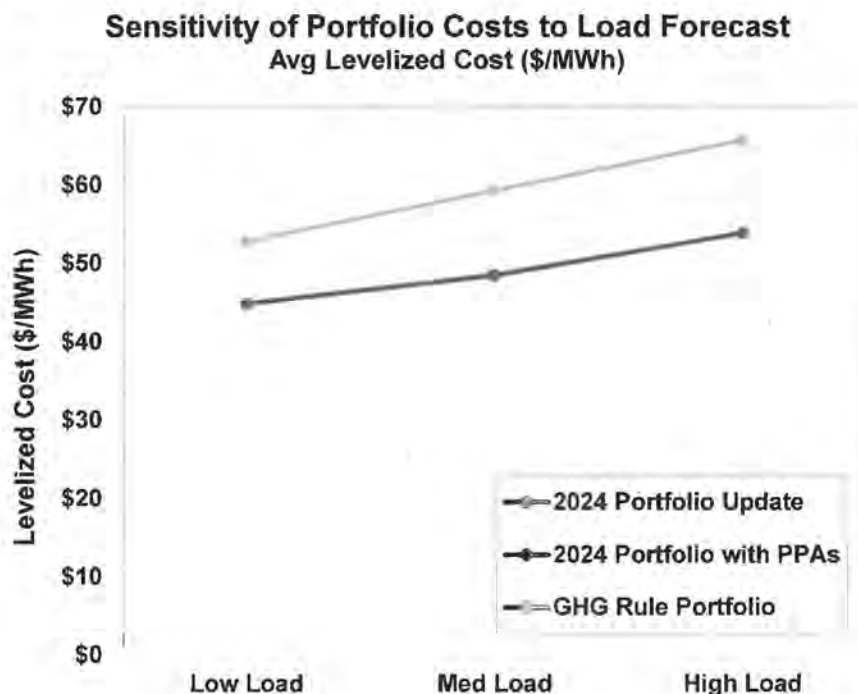
Results also indicate that power costs would be significantly higher under scenarios reflecting the EPA GHG Rule. Incremental NPV power supply costs under the 2024 GHG Rule Portfolio are projected to be \$6.5 billion higher over the Study Period, much of this incremental cost being a direct result of resource and transmission additions due to the retirement of Cross.

Table 5 provides a comparison of NPV costs under fuel price sensitivity assumptions and the range of NPV cost uncertainty for each portfolio. Results indicate that the 2024 Portfolio with PPAs and the 2024 Portfolio Update have nearly an identical response to changes in fuel prices. The GHG Rule Portfolio reflects a much larger range of uncertainty given much greater reliance upon NGCC resources.

Table 5. Fuel Price Sensitivity Results

Supplemental Portfolios	NPV Power Costs (\$B)			Range of Uncertainty
	Reference Case	Low Fuel Price	High Fuel Price	
2024 Portfolio Update	\$29.3	\$27.6	\$33.3	\$5.7
2024 Portfolio with PPAs	\$29.2	\$27.5	\$33.2	\$5.7
GHG Rule Portfolio	\$35.7	\$33.4	\$42.5	\$9.1

Figure 5⁹ illustrates average levelized costs for the portfolios under different load forecast sensitivity case assumptions. As can be seen in the chart, the 2024 Portfolio Update and the 2024 Portfolio with PPAs are projected to have nearly identical average levelized costs across the load forecast sensitivities, indicating similar sensitivity to changes in load. Importantly, the load sensitivity analysis confirms there is not significant risk to Santee Cooper's customers should projected load additions not materialize. However, the GHG Rule Portfolio is projected to result in an increase in levelized cost from approximately \$8/MWh for the Low Load Forecast to approximately \$12/MWh for the High Load Forecast, indicating that costs of the GHG Rule Portfolio are projected to be impacted much more significantly by changes in load.

Figure 5. Load Forecast Sensitivity Case Results

⁹ The 2024 Portfolio Update and 2024 Portfolio with PPAs are indistinguishable in this chart.

APPENDIX D: NPV POWER COST SUMMARY

Table D-1: Net Present Value Power Costs by Portfolio Across Sensitivities (\$B; 2023\$)

Portfolio	Sensitivity Case	Study Period (2024-52)	20 Years (2031-50)
2023 Preferred Portfolio (Reoptimized)	Reference	\$29.3	\$21.0
2024 Portfolio Update	Reference	\$29.3	\$21.0
2024 Portfolio with PPAs	Reference	\$29.2	\$21.0
GHG Rule Portfolio	Reference	\$35.7	\$27.2
2024 Portfolio Update	Low Fuel	\$27.6	\$19.6
2024 Portfolio with PPAs	Low Fuel	\$27.5	\$19.6
GHG Rule Portfolio	Low Fuel	\$33.4	\$25.2
2024 Portfolio Update	High Fuel	\$33.3	\$24.1
2024 Portfolio with PPAs	High Fuel	\$33.2	\$24.0
GHG Rule Portfolio	High Fuel	\$42.5	\$32.8
2024 Portfolio Update	Med CO2	\$36.6	\$26.8
2024 Portfolio with PPAs	Med CO2	\$36.5	\$26.8
GHG Rule Portfolio	Med CO2	\$40.8	\$30.9
2024 Portfolio Update	High CO2	\$49.6	\$36.9
2024 Portfolio with PPAs	High CO2	\$49.6	\$36.9
GHG Rule Portfolio	High CO2	\$50.5	\$37.9
2024 Portfolio Update	High Load	\$38.2	\$28.5
2024 Portfolio with PPAs	High Load	\$38.2	\$28.5
GHG Rule Portfolio	High Load	\$46.6	\$36.6
2024 Portfolio Update	Low Load	\$21.8	\$14.8
2024 Portfolio with PPAs	Low Load	\$21.8	\$14.8
GHG Rule Portfolio	Low Load	\$25.6	\$18.5
2024 Portfolio with Self Build NGCC	Reference	\$29.3	\$21.1

DUKE 2023 CAROLINAS RESOURCE PLAN*

Table 2: Portfolio Results

CAROLINAS RESOURCE PLAN PORTFOLIOS	P1 Base		P2 Base		P3 Base	
DEC/DEP COMBINED SYSTEM RESOURCES (NAMEPLATE MW) START OF YEAR	2033	2038	2033	2038	2033	2038
Total Capacity from Grid Edge & Customer Programs ¹	2,087	2,536	2,087	2,536	2,087	2,536
Incremental System Solar (incl. ~3,000 MW of projects in flight)	15,350	15,750	8,775	14,100	8,775	14,625
Incremental Onshore Wind	1,580	2,850	1,200	2,700	1,200	2,750
Incremental Offshore Wind	2,400	2,400	1,500	1,500	0	0
Incremental Advanced Nuclear Capacity	0	3,000	0	2,400	0	2,400
Incremental Energy Storage ²	6,374	8,854	6,374	8,400	3,654	7,354
Incremental Gas (CCF)	2,720	2,720	4,000	4,000	4,000	4,000
Incremental Gas (CT)	2,550	2,550	2,125	2,125	2,125	2,125
Potential Coal Capacity ³	2,162	0	3,054	0	4,473	0
Total Coal Retirement by End of 2035 ⁴	3,445		3,445		3,445	
PORTFOLIO COST (2033, 2038)	2033	2038	2033	2038	2033	2038
Average Monthly Residential Bill Impact for a Household Using 100% Gas (DEP/DEC Combined System) (\$/month) 2033 / 2038 ⁵	\$65	\$70	\$42	\$55	\$35	\$55
Average Monthly Residential Bill Impact for a Household Using 100% Gas (DEP) (\$/month) 2033 / 2038 ⁶	\$86	\$77	\$72	\$63	\$41	\$48
Average Monthly Residential Bill Impact for a Household Using 100% Gas (DEC) (\$/month) 2033 / 2038 ⁷	\$41	\$55	\$32	\$51	\$30	\$55
Present Value Revenue Requirement (PVRR) (DEP/DEC Combined System) through 2038 / 2050 (\$M)	\$76	\$138	\$65	\$126	\$66	\$119
PVRR (DEP) (\$M) through 2038 / 2050	\$34	\$67	\$28	\$59	\$26	\$48
PVRR (DEC) (\$M) through 2038 / 2050	\$42	\$77	\$40	\$71	\$40	\$71
INCREASINGLY CLEAN RESOURCE MIX	2033	2038	2033	2038	2033	2038
CO2 Intensity (DEP/DEC Combined) (lb/MWh)	217	131	257	160	313	182
Year in which 70% CO2 Reduction Achieved	2038		2033		2035	
RELIABILITY & FLEXIBILITY	2033	2038	2033	2038	2033	2038
95th Percentile Expected Short-Lived Supply (MW)	12,122	11,500	9,206	12,550	9,201	12,000
Average CC Starts per Week per Year	36	39	38	44	60	61
ENERGY TRANSITION RISK ASSESSMENT	2033	2038	2033	2038	2033	2038
Cumulative Nameplate MW Addition of Resources with Limited Operational History in the Carolinas ¹	10,274	15,704	9,114	14,994	4,894	12,804
Cumulative Nameplate MW Addition, Combined Coal and Gas System ²	31,857	38,737	27,107	38,312	22,857	37,937
Cumulative Nameplate MW Addition as % of Current Combined Coal and Gas System	73%	91%	62%	88%	53%	86%
Cumulative Capital Dollar Requirement, Combined Coal and Gas System (\$B)	\$85	\$138	\$69	\$101	\$44	\$82
Overall Pathway Risk: Reduced in Cost, Reliability, and Plan Execution						

Note 1: Includes winter peak impact of load modifiers (utility-sponsored energy efficiency, behind-the-meter solar, critical peak pricing), integrated Volt-VAR control (IVVC) and demand response programs.

Note 2: Includes stand-alone storage, paired storage, pumped storage hydro and forecast.

Note 3: New natural gas facilities will be capable of burning zero-carbon hydrogen in the future; hydrogen blending assumed to begin in 2035.

Note 4: Cliffside 6 continues to operate on 100% natural gas.

Note 5: Average retail rate impact across all customer classes applied to representative residential bill.

Note 6: Includes onshore wind, offshore wind, battery energy storage and advanced nuclear.

Note 7: Includes solar and battery projects currently in advanced development.

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

EXHIBIT

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GIPLSF-2G

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Figure 3-6: P1 Base Summary

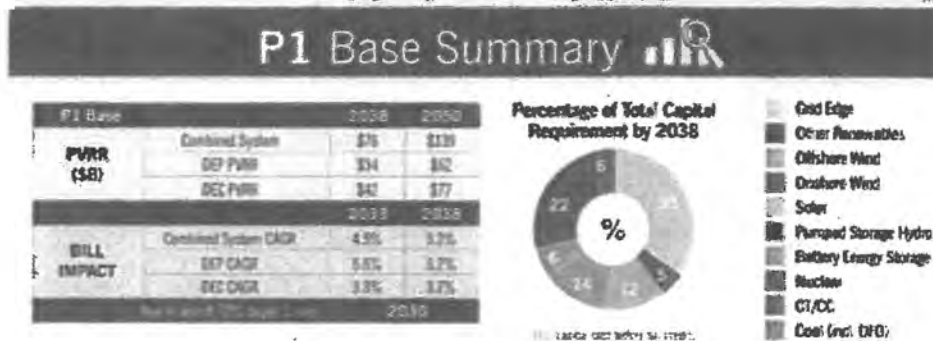


Figure 3-6: P2 Base Summary

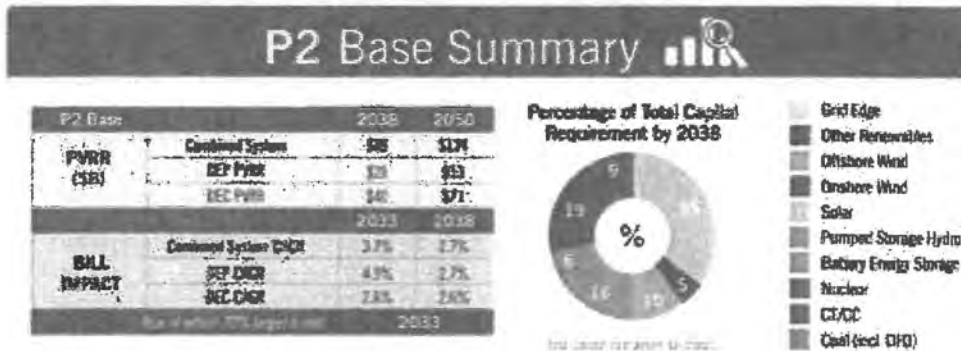


Figure 3-7: P3 Base Summary

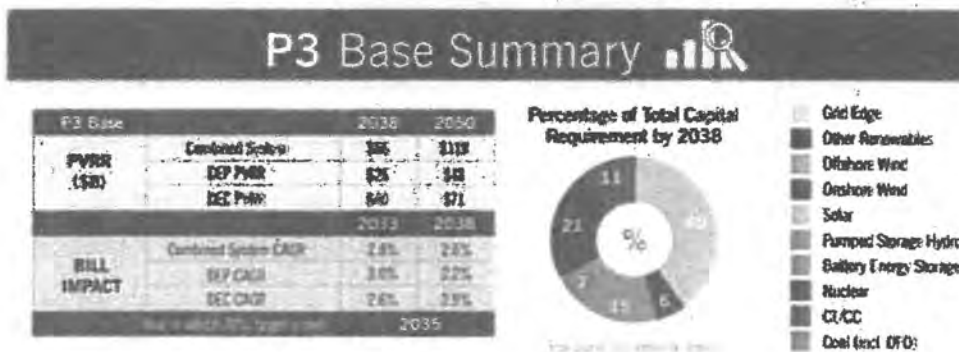


Table C-58: Present Value of Revenue Requirements through 2038 and 2050 (\$B)

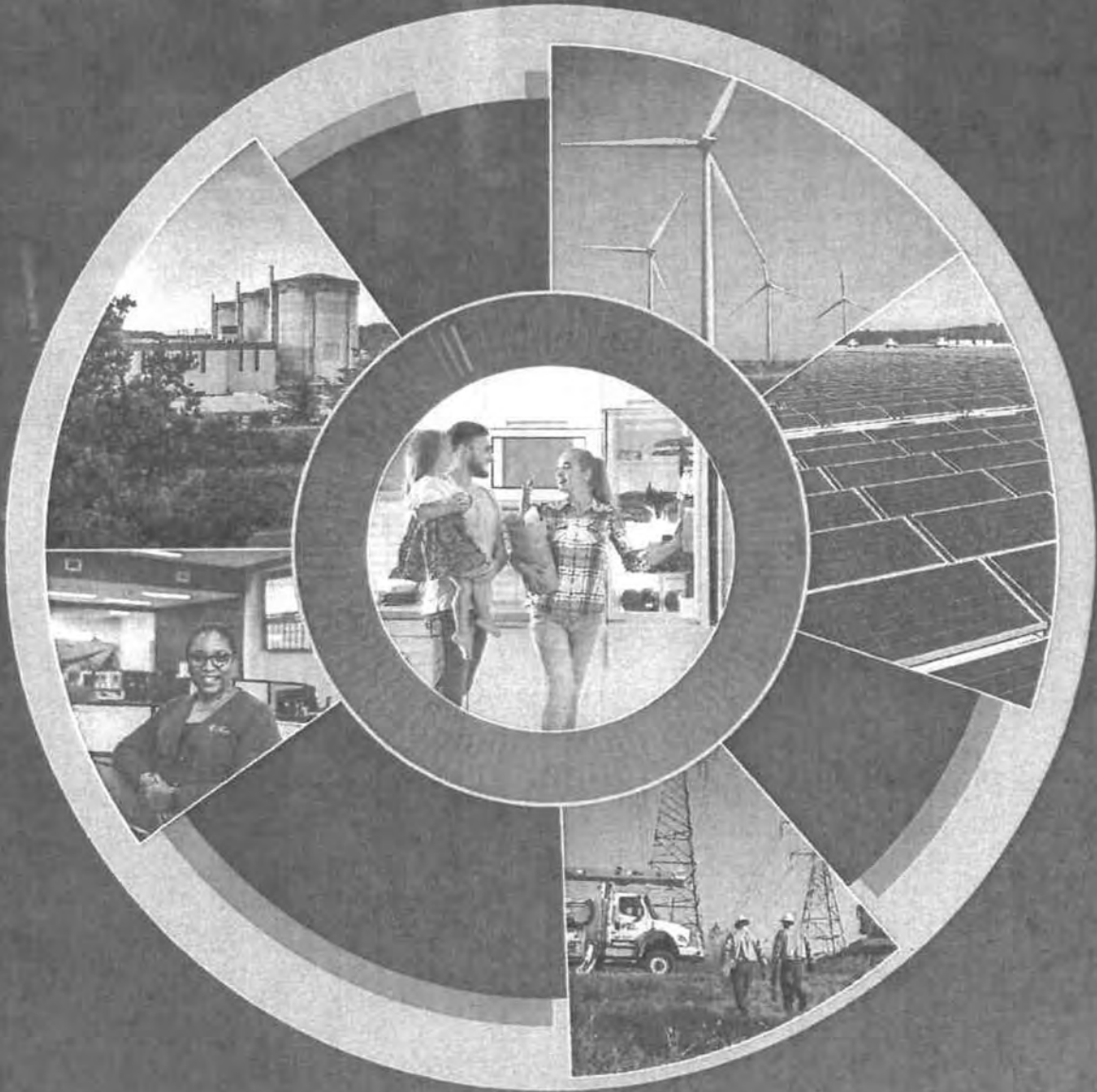
	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P1 Base	42.4	33.6	76.1	76.7	62.0	138.7
P2 Base	40.2	28.4	68.6	70.7	53.2	123.8
P3 Base	39.7	26.4	66.1	70.7	48.3	119.0

Table C-63: PVRR through 2038 Across Resource Capital and Fuel Price Performance Sensitivities, Combined Carolinas System (\$B)

Case	P1 Base	P2 Base	P3 Base
Base Capital/High Fuel	82	75	73
Base Capital/Base Fuel	76	69	66
Base Capital/Low Fuel	71	64	61
Low Capital/High Fuel	75	71	70
Low Capital/Base Fuel	69	65	63
Low Capital/Low Fuel	65	60	58
High Capital/High Fuel	84	77	74
High Capital/Base Fuel	78	70	68
High Capital/Low Fuel	73	65	62



2023 Carolinas Resource Plan



BUILDING A SMARTER ENERGY FUTURE®

Table 2: Portfolio Results

CAROLINAS RESOURCE PLAN PORTFOLIOS	P1 Base		P2 Base		P3 Base	
DEC/DEP COMBINED SYSTEM RESOURCES [NAMEPLATE MW] START OF YEAR	2033	2038	2033	2038	2033	2038
Total Contribution from Grid Edge & Customer Programs ¹	2,087	2,536	2,087	2,536	2,087	2,536
Incremental System Solar (excl. ~3,000 MW of projects in dev.)	13,350	15,750	8,775	14,100	8,775	14,625
Incremental Onshore Wind	1,500	2,250	1,200	2,100	1,200	2,250
Incremental Offshore Wind	2,400	2,400	1,600	1,600	0	0
Incremental Advanced Nuclear Capacity	0	3,000	0	2,400	0	2,400
Incremental Energy Storage ²	6,374	8,054	6,314	8,894	3,694	7,954
Incremental Gas (CC) ³	2,720	2,720	4,080	4,080	4,080	4,080
Incremental Gas (CT) ³	2,550	2,550	2,125	2,125	2,125	2,975
Remaining Coal Capacity ⁴	2,162	0	3,064	0	4,473	0
Total Coal Retirements (MW) by End of 2035⁴	8,445		8,445		8,445	
PORTFOLIO COST (2033/2038)	2033	2038	2033	2038	2033	2038
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP/DEC Combined System) (\$/month) 2033 2038 ⁵	\$60	\$70	\$48	\$56	\$35	\$55
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) (\$/month) 2033 2038 ⁵	\$86	\$77	\$72	\$63	\$41	\$48
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) (\$/month) 2033 2038 ⁵	\$41	\$65	\$32	\$51	\$30	\$59
	2038	2050	2038	2050	2038	2050
Present Value Revenue Requirement (PVRR) (DEP/DEC Combined System) through 2038 2050 (\$B)	\$76	\$139	\$69	\$124	\$66	\$119
PVRR (DEP) (\$B) through 2038 2050	\$34	\$62	\$28	\$53	\$26	\$48
PVRR (DEC) (\$B) through 2038 2050	\$42	\$77	\$40	\$71	\$40	\$71
INCREASINGLY CLEAN RESOURCE MIX	2033	2038	2033	2038	2033	2038
CO2 Intensity (DEP/DEC Combined) [lbs/MWh]	217	131	267	163	313	182
Year in which 70% CO2 Reduction Achieved	2030		2033		2035	
RELIABILITY & FLEXIBILITY	2033	2038	2033	2038	2033	2038
95th Percentile Expected Net Load Ramp (MW/hr)	12,122	13,581	9,206	12,553	9,201	12,880
Average CC Starts per Unit per Year	86	90	39	64	60	81
ENERGY TRANSITION RISK ASSESSMENT	2033	2038	2033	2038	2033	2038
Cumulative Nameplate MW Additions of Resources with Limited Operational History in the Carolinas ⁶	10,274	15,704	9,114	14,994	4,894	12,604
Cumulative Nameplate MW Additions, Combined Carolinas System ⁷	31,907	39,737	27,107	38,312	22,887	37,297
Cumulative Nameplate MW Additions as % of Current Combined Carolinas System	73%	91%	62%	88%	53%	86%
Cumulative Capital Dollar Requirement, Combined Carolinas System (\$B)	\$85	\$130	\$59	\$101	\$44	\$92
Overall Pathway Risk Related to Cost, Reliability, and Plan Execution						

Note 1: Includes winter peak impact of load modifiers (utility-sponsored energy efficiency, behind-the-meter solar, critical peak pricing), integrated Volt-VAR control (IVVC) and demand response programs.

Note 2: Includes stand-alone storage, paired storage, pumped storage hydro and forecast.

Note 3: New natural gas facilities will be capable of burning zero-carbon hydrogen in the future; hydrogen blending assumed to begin in 2035.

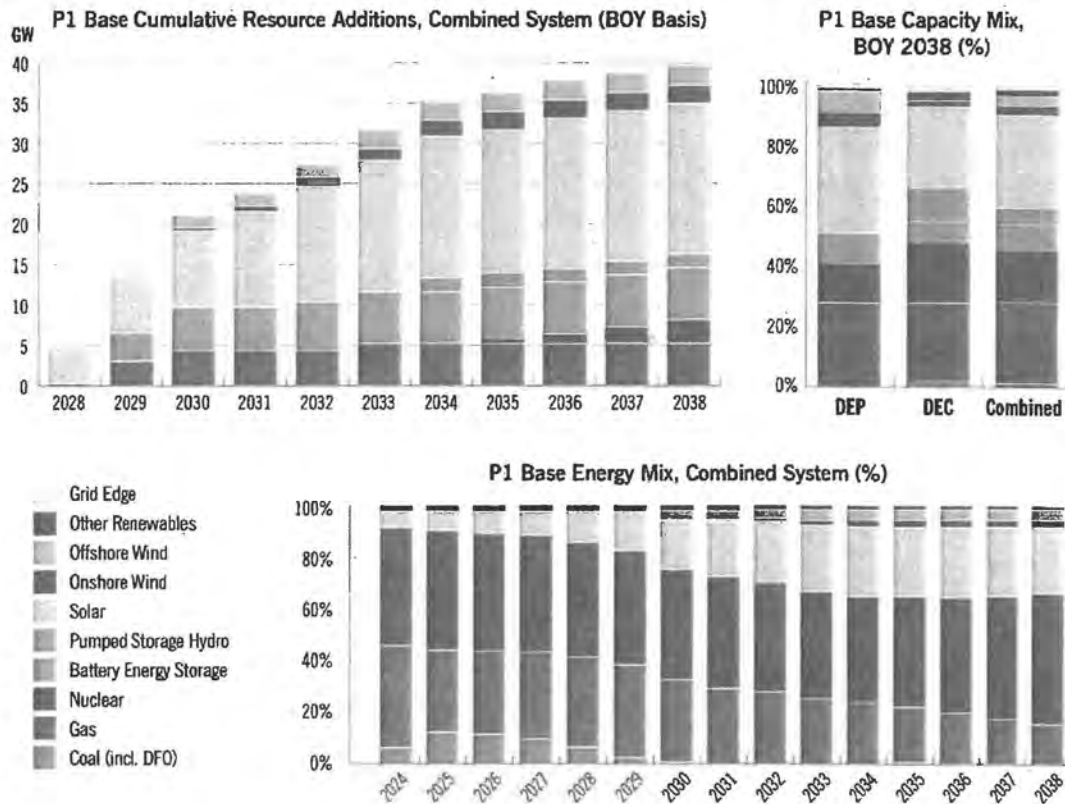
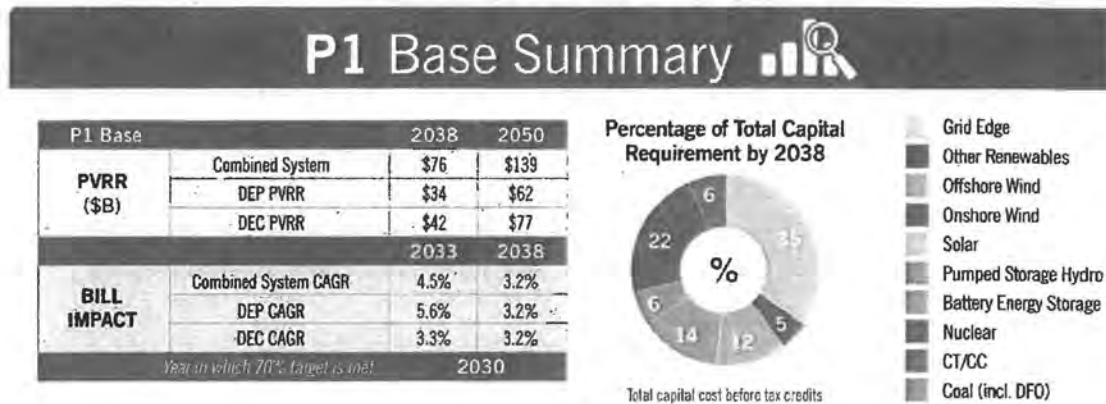
Note 4: Cliffside 6 continues to operate on 100% natural gas.

Note 5: Average retail rate impact across all customer classes applied to representative residential bill.

Note 6: Includes onshore wind, offshore wind, battery energy storage and advanced nuclear.

Note 7: Includes solar and battery projects currently in advanced development.

Figure 3-5: P1 Base Summary

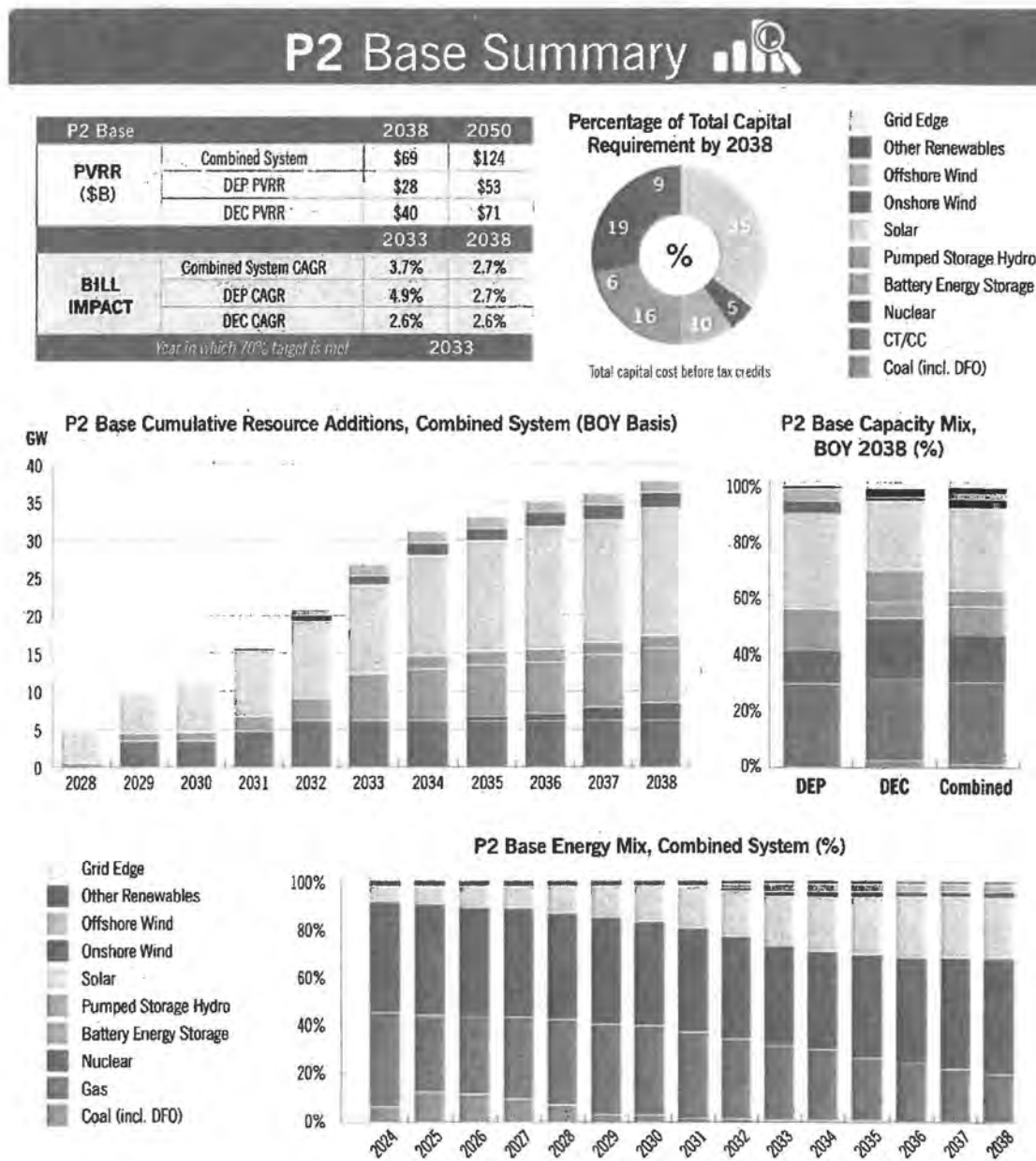


P1 Coal Retirements by Year (MW, effective by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
DEP						1,766	1,409						
DEC		426*				1,306	2,220				1,318		
TOTAL		426*				3,072	3,629				1,318		

*Allen Units 1 & 5 are planned to retire by December 31, 2024.

Figure 3-6: P2 Base Summary

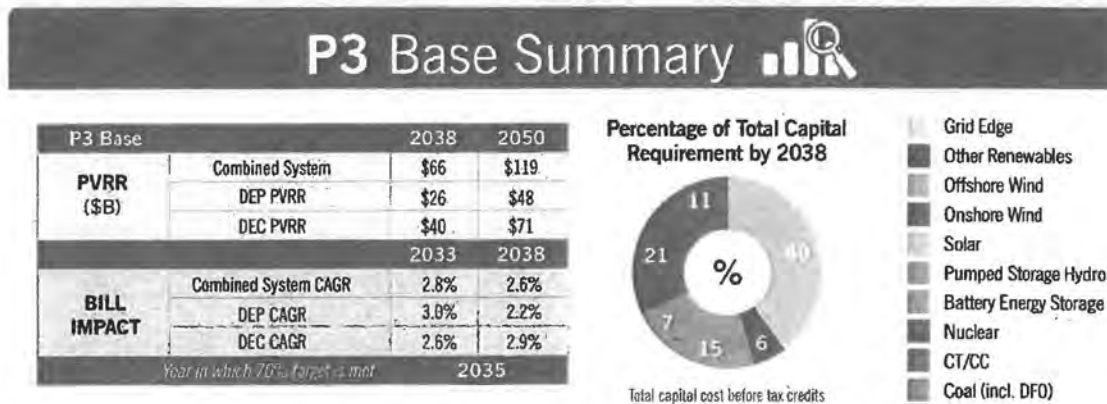


P2 Coal Retirements by Year (MW, effective by January 1 of year shown)

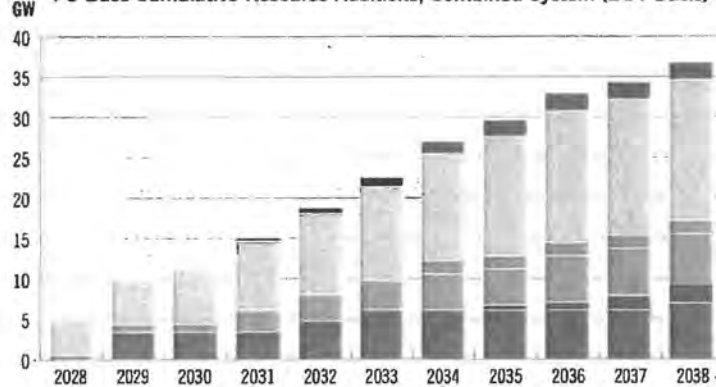
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
DEP						1,053		713		1,409			
DEC		426*				760		546	1,318				2,220
TOTAL		426*				1,813		1,259	1,318	1,409			2,220

*Allen Units 1 & 5 are planned to retire by December 31, 2024.

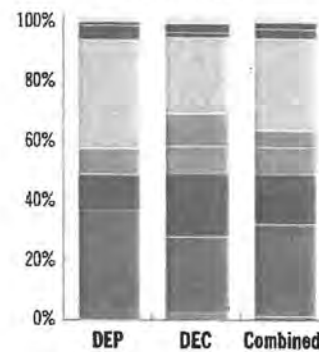
Figure 3-7: P3 Base Summary



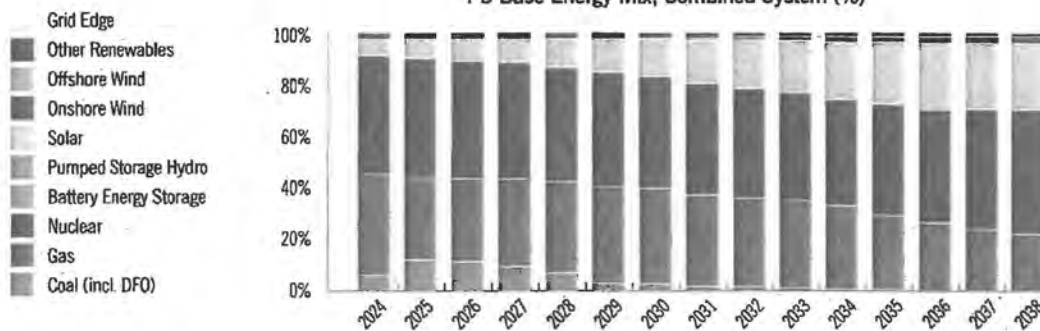
P3 Base Cumulative Resource Additions, Combined System (BOY Basis)



P3 Base Capacity Mix, BOY 2038 (%)



P3 Base Energy Mix, Combined System (%)



P3 Coal Retirements by Year (MW, effective by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
DEP						1,053		713			1,409		
DEC		426*				760		546	1,318				2,220
TOTAL		426*				1,813		1,259	1,318		1,409		2,220

*Allen Units 1 & 5 are planned to retire by December 31, 2024.

Table C-58: Present Value of Revenue Requirements through 2038 and 2050 (\$B)

	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P1 Base	42.4	33.6	76.1	76.7	62.0	138.7
P2 Base	40.2	28.4	68.6	70.7	53.2	123.8
P3 Base	39.7	26.4	66.1	70.7	48.3	119.0

By design, Pathway 1 achieves the Interim Target at an accelerated pace relative to Pathway 2 and Pathway 3. The extraordinarily aggressive pace of energy transition contemplated in Pathway 1 is reflected in the high cost of P1 Base relative to the other portfolios. To procure and deploy new resources in the unprecedented volumes required for P1 Base, particularly by 2030 (1,600 MW of offshore wind, approximately 9,600 MW of solar, approximately 5,300 MW of batteries, 300 MW of onshore wind, two CCs, and four CTs), the Companies would expect to incur costs well above those captured in the generic unit cost forecasts used in the resource planning analysis. As a proxy for these unknown market conditions, the Companies added a 20% cost risk premium to the capital costs for the scope, scale, and pace of resource additions in P1 Base for the purposes of this comparison. Even this adjustment may be conservative. As a tradeoff for the extended timeline to achieve the Interim Target, P2 Base and P3 Base result in combined system PVRRs that are \$7.5B and \$10B less, respectively, than P1 Base through the Base Planning Period, and approximately \$15B and \$20B less, respectively, through 2050. Extending the timeline for achieving the Interim Target allows for use of base resource availability assumptions and for advanced nuclear to contribute to the Interim Target in P3 Base, instead of requiring offshore wind. Advanced nuclear is economically selected in the mid-2030s in all portfolios, but allowing time for this resource to contribute to achieving the Interim Target also allows for the avoidance of more costly resources in the near term. Furthermore, the additional years allowed to achieve the Interim Target permit the Companies to take advantage of cost declines for resources such as solar and batteries, and to maintain lower levels of annual resource integration, increasing the executability of P2 Base and P3 Base relative to P1 Base at the same time. Overall, the lowest cost Core Portfolio is P3 Base.

Shown below in Table C-59 through Table C-62 are the PVRRs for each Portfolio Variant and Sensitivity Analysis Portfolio relative to the Core Portfolio in its respective Pathway. For this comparison, the Companies are comparing these Portfolio Variants and Sensitivity Analysis Portfolios to the Core Portfolios excluding the reliability resources identified in the Reliability Verification step. The Companies calculated the PVRR deltas from the unadjusted Core Portfolios to create a comparison on an equivalent basis. The Reliability Verification step was only performed for the Core Portfolios.

Minimax Regret Analysis

In addition to the single variable sensitivity analysis, the Companies also conducted performance sensitivity analysis on combinations of the high and low forecasts for resource capital costs and fuel prices. Table C-63 below shows the PVRR through 2038 across these 27 cases. In each sensitivity case, P3 Base has the lowest PVRR of the three.

Table C-63: PVRR through 2038 Across Resource Capital and Fuel Price Performance Sensitivities, Combined Carolinas System (\$B)

Case	P1 Base	P2 Base	P3 Base
Base Capital/High Fuel	82	75	73
Base Capital/Base Fuel	76	69	66
Base Capital/Low Fuel	71	64	61
Low Capital/High Fuel	75	71	70
Low Capital/Base Fuel	69	65	63
Low Capital/Low Fuel	65	60	58
High Capital/High Fuel	84	77	74
High Capital/Base Fuel	78	70	68
High Capital/Low Fuel	73	65	62

Put another way, P3 Base minimizes the maximum customer exposure to cost increase. Table 3-5 below presents the "regrets" for each case, defined as the difference between the PVRR for a given portfolio in a given case and the minimum portfolio PVRR for that same case. As Table C-64 below shows, P3 Base has the lowest maximum regret across the cases. This is referred to as "minimax regrets" analysis.

Table C-64: PVRR Regret through 2038 Across Resource Capital and Fuel Price Performance Sensitivities, Combined Carolinas System (\$B)

Case	P1 Base	P2 Base	P3 Base
Base Capital/High Fuel	9.3	2.2	0.0
Base Capital/Base Fuel	10.0	2.5	0.0
Base Capital/Low Fuel	10.4	2.6	0.0
Low Capital/High Fuel	5.8	1.5	0.0
Low Capital/Base Fuel	6.5	1.8	0.0
Low Capital/Low Fuel	6.9	1.9	0.0
High Capital/High Fuel	9.4	2.3	0.0
High Capital/Base Fuel	10.1	2.6	0.0
High Capital/Low Fuel	10.5	2.7	0.0

LG&E AND KU 2024 RESOURCE PLAN*

9 Financial Information

Annual revenue requirements and the present value of revenue requirements ("PVRR") are shown in Table 9-1 for the Mid energy requirements, mid gas, mid coal-to-gas ratio fuel price ("Mid Fuel") case. The discount rate used in the present value calculation is 6.56%. Annual revenue requirements include variable and fixed costs for both new and existing units and capital costs for new units.

Table 9-1: Annual Revenue Requirements (Mid Energy Requirements, Mid Fuel Case)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Revenue Requirements (\$M)	2,153	2,120	2,431	2,129	2,781	2,987	3,095	3,103	3,049	3,048	2,508	3,086	3,083	2,939	2,958
PVRR (\$M: 2024 Dollars)	13,657														
Mid Energy Requirements (GWh)	32,808	32,867	33,668	34,806	36,057	38,292	40,569	41,200	41,033	40,971	40,949	41,057	40,930	40,949	40,943
costs/LWh	6.56	6.45	7.22	6.12	7.71	7.80	7.63	7.53	7.43	7.44	6.12	7.52	7.53	7.18	7.22

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.



**2024 Joint Integrated
Resource Plan of
Louisville Gas and Electric
Company and Kentucky
Utilities Company**



PPL companies

Case No. 2024-00326

Volume I

9 Financial Information

Annual revenue requirements and the present value of revenue requirements ("PVRR") are shown in Table 9-1 for the Mid energy requirements, mid gas, mid coal-to-gas ratio fuel price ("Mid Fuel") case. The discount rate used in the present value calculation is 6.56%. Annual revenue requirements include variable and fixed costs for both new and existing units and capital costs for new units.

Table 9-1: Annual Revenue Requirements (Mid Energy Requirements, Mid Fuel Case)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Revenue Requirements (\$M)	2,153	2,120	2,431	2,129	2,781	2,987	3,095	3,103	3,049	3,048	2,508	3,086	3,083	2,939	2,958
PVRR (\$M; 2024 Dollars)	13,657														
Mid Energy Requirements (GWh)	32,808	32,867	33,668	34,806	36,057	38,292	40,569	41,200	41,033	40,971	40,949	41,057	40,930	40,949	40,943
cents/kWh	6.56	6.45	7.22	6.12	7.71	7.80	7.63	7.53	7.43	7.44	6.12	7.52	7.53	7.18	7.22

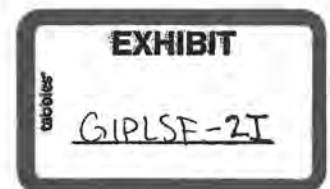
INDIANA MICHIGAN POWER 2024 INDIANA IRP*

Table 55 provides Affordability metrics for each portfolio developed.

Table 55. Affordability Metrics Analysis

Portfolio	Short Term	Long Term
	Full OASB Power Supply (%)	NPVHR (\$B)
	2024-2031	2025-2034
Base Reference	-0.5%	\$32.0
High Economic Growth	1.8%	\$39.3
Low Economic Growth	-2.3%	\$25.7
Enhanced Environmental Regulations	0.7%	\$33.2
Base under EPA Section 111(b)(4) Requirements	0.7%	\$33.3
Low Carbon: Expanded Build Limits	4.5%	\$41.4
Low Carbon: Transition to Objective	1.3%	\$39.8
Base with High Indiana Load	-0.1%	\$34.8
Base with Low Indiana Load	-0.7%	\$28.3
Exit OVEC ICAP in 2030	-0.4%	\$32.1
Rockport Unit 1 Retires 2025	-0.5%	\$32.0
Rockport Unit 1 Retires 2026	-0.5%	\$32.4
Expanded Wind Availability (Base)	-0.5%	\$31.8
Expanded Wind Availability (EER)	0.5%	\$32.8
High Technology Costs	0.7%	\$34.6

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.





INDIANA INTEGRATED RESOURCE PLANNING REPORT

to the:
Indiana Utility Regulatory Commission

Submitted Pursuant to:
Commission Rule 170 IAC 4-7

March 28, 2025

and 90th percentile NPVRRs obtained from stochastic risk analysis, indicates the financial impact that economic uncertainties could have on Candidate Portfolios. Lower values are preferred, as this indicates a lower variability of expected customer costs across a wide range of long-term market conditions. These results are presented in Section 9.8.

Table 55 provides Affordability metrics for each portfolio developed.

Table 55. Affordability Metrics Analysis

Portfolio	Short Term	Long Term
	7-yr CAGR Power Supply (%)	NPVRR (\$B)
	2024-2031	2025-2044
Base Reference	-0.5%	\$32.0
High Economic Growth	1.6%	\$39.3
Low Economic Growth	-2.3%	\$25.7
Enhanced Environmental Regulations	0.7%	\$33.2
Base under EPA Section 111(b)(d) Requirements	0.7%	\$33.3
Low Carbon: Expanded Build Limits	4.5%	\$41.4
Low Carbon: Transition to Objective	1.3%	\$39.9
Base with High Indiana Load	-0.1%	\$34.9
Base with Low Indiana Load	-0.7%	\$28.3
Exit OVEC ICPA in 2030	-0.4%	\$32.1
Rockport Unit 1 Retires 2025	-0.5%	\$32.6
Rockport Unit 1 Retires 2026	-0.5%	\$32.4
Expanded Wind Availability (Base)	-0.5%	\$31.8
Expanded Wind Availability (EER)	0.5%	\$32.8
High Technology Costs	0.7%	\$34.8

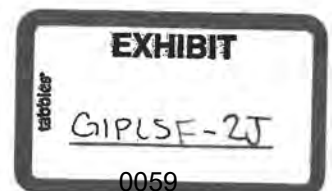
Over the seven-year period, the variation in the expected growth of customer rates is driven by the differences in short-term resource additions across the Cases. As expected, the Low Economic

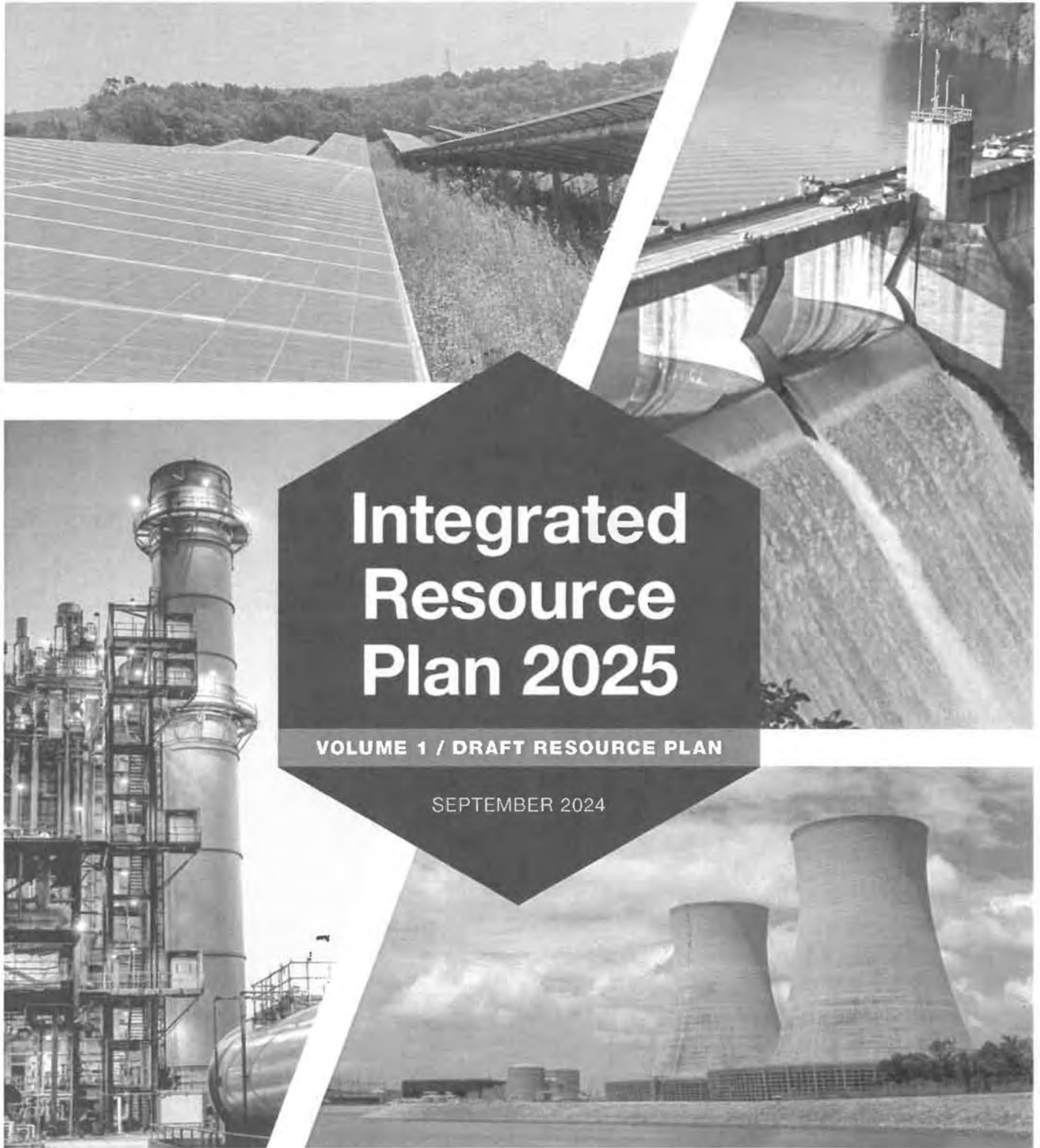
TVA DRAFT 2025 IRP*

Table 4-8: Scorecard Metrics by Scenario and Strategy

Metric / Strategy	Scenarios					
	1 Ref without GHG Rule	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG Rule
Present Value of Revenue Requirements (PVRR, \$B)						
A	\$154	\$191	\$130	\$184	\$228	\$156
B	\$177	\$216	\$152	\$213	\$255	\$180
C	\$158	\$195	\$134	\$187	\$226	\$160
D	\$159	\$197	\$136	\$188	\$231	\$162
E	\$171	\$208	\$146	\$207	\$236	\$174
System Average Cost (\$/MWh)						
A	\$72	\$81	\$68	\$86	\$81	\$76
B	\$83	\$91	\$80	\$100	\$91	\$88
C	\$74	\$82	\$70	\$88	\$81	\$78
D	\$75	\$83	\$72	\$88	\$83	\$79
E	\$80	\$88	\$77	\$97	\$85	\$85

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.





Integrated Resource Plan 2025

VOLUME 1 / DRAFT RESOURCE PLAN

SEPTEMBER 2024

TVA **TENNESSEE
VALLEY
AUTHORITY**

Table 4-7: Scenario 6 Scorecard (Reference with Greenhouse Gas Rule)

Scenario 6 – Reference (with Greenhouse Gas Rule)		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, \$B)	\$156	\$180	\$160	\$162	\$174
	System Average Cost (\$/MWh)	\$76	\$88	\$78	\$79	\$85
	Total Resource Cost (\$B)	\$164	\$199	\$179	\$201	\$192
Risk Informed	Risk / Benefit Ratio	1.18	1.06	1.16	1.12	1.11
	Risk Exposure (\$B)	\$15.6	\$13.7	\$13.1	\$13.6	\$14.0
Environmentally Responsible	CO ₂ Direct Emissions (Million Tons)	30	24	25	26	27
	CO ₂ Intensity (lbs/MWh)	365	296	305	337	334
	Water Consumption Intensity (Million Gallons/MWh)	283	313	274	294	302
	Waste Intensity (Million Tons/MWh)	1.4	1.4	1.3	1.4	1.4
	Land Use Intensity in 2050 (Acres/MWh)	0.7	0.6	0.8	0.8	0.7
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation in \$/MWh)	3.8%	3.7%	3.4%	3.4%	3.5%
	Flexible Resource Coverage Ratio in 2050	1.16	1.17	1.14	1.08	1.13
	Energy Curtailment Ratio (%)	0.22%	0.20%	0.53%	0.26%	0.22%

4.9.2 Scorecard Results by Metric

Scorecard results by metric, shown in the table below, compare how the five strategies performed across all scenarios for each metric.

Table 4-8: Scorecard Metrics by Scenario and Strategy

Metric / Strategy	Scenarios					
	1 Ref without GHG Rule	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG Rule
Present Value of Revenue Requirements (PVRR, \$B)						
A	\$154	\$191	\$130	\$184	\$228	\$156
B	\$177	\$216	\$152	\$213	\$255	\$180
C	\$158	\$195	\$134	\$187	\$226	\$160
D	\$159	\$197	\$136	\$188	\$231	\$162
E	\$171	\$208	\$146	\$207	\$236	\$174
System Average Cost (\$/MWh)						
A	\$72	\$81	\$68	\$86	\$81	\$76
B	\$83	\$91	\$80	\$100	\$91	\$88
C	\$74	\$82	\$70	\$88	\$81	\$78
D	\$75	\$83	\$72	\$88	\$83	\$79
E	\$80	\$88	\$77	\$97	\$85	\$85

PUBLIC DISCLOSURE

Table 7.2.1 Budget 2025 External Peak Adjustments for Large Loads

<u>Year</u>	<u>Total</u>
2024	REDACTED
2025	REDACTED
2026	REDACTED
2027	REDACTED
2028	REDACTED
2029	REDACTED
2030	REDACTED
2031	REDACTED
2032	REDACTED
2033	REDACTED
2034	REDACTED
2035	REDACTED
2036	REDACTED
2037	REDACTED
2038	REDACTED
2039	REDACTED
2040	REDACTED
2041	REDACTED
2042	REDACTED
2043	REDACTED
2044	REDACTED

7.3 TRIANGULAR DISTRIBUTION

The triangular distribution is a continuous probability distribution with the following parameters:

a: $a \in (-\infty, \infty)$

b: $a < b$

c: $a \leq c \leq b$

In the case of metered versus announced uncertainty, a represents the minimum metered/announced ratio, b represents maximum metered/announced ratio and c represents the most likely metered/announced ratio.



BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 56002**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2025 Integrated Resource Plan ("2025 IRP"), filed in Docket No. 56002, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 1, which contains certain information regarding the Company's demand-side plans, load and energy forecast data, reserve margin, unit retirements, unit upgrades, proprietary planning processes, wholesale-to-retail offers, and Critical Energy Infrastructure Information ("CEII") in the form of drawings/schematics of dam infrastructure of the Company's hydro facilities (collectively, the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the trade secret portions of the Information contain competitively sensitive cost information related to optimal reserve margins and reserve margin scenarios, processes and data used by Georgia Power in analyzing resource addition and retirement schedules, demand-side program details, financial assumptions and other confidential details. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. With this competitive advantage, Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers. The Information also includes sensitive details concerning Georgia Power's infrastructure that must be protected from public disclosure in the interests of system security and reliability. Such portions of the Information contain Critical Energy Infrastructure Information as defined by the Code of Federal Regulations Section 388.113.

Certain trade secret portions of the Information provided includes detailed forecasted information regarding the Company's future energy and demand growth, which could be used to determine the Company's short-term capacity needs. If revealed to the public, a generation wholesaler or power marketer could use the trade secret portions of the Information to tailor proposals with the intention of pricing products in a manner that would undermine the Company's market position. Such disclosure could unfairly allow competitors to manipulate the wholesale market and ultimately harm retail customers through higher rates and less reliability. Lastly, the Company's competitors are not required to file their respective forecast information.



The trade secret portions of the Information described above is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company affiliate personnel are granted access to the trade secret portions of the Information. Those personnel receive access on a "need to know" basis only. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 1 of the Company's 2025 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).



Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 27 day of January, 2025.



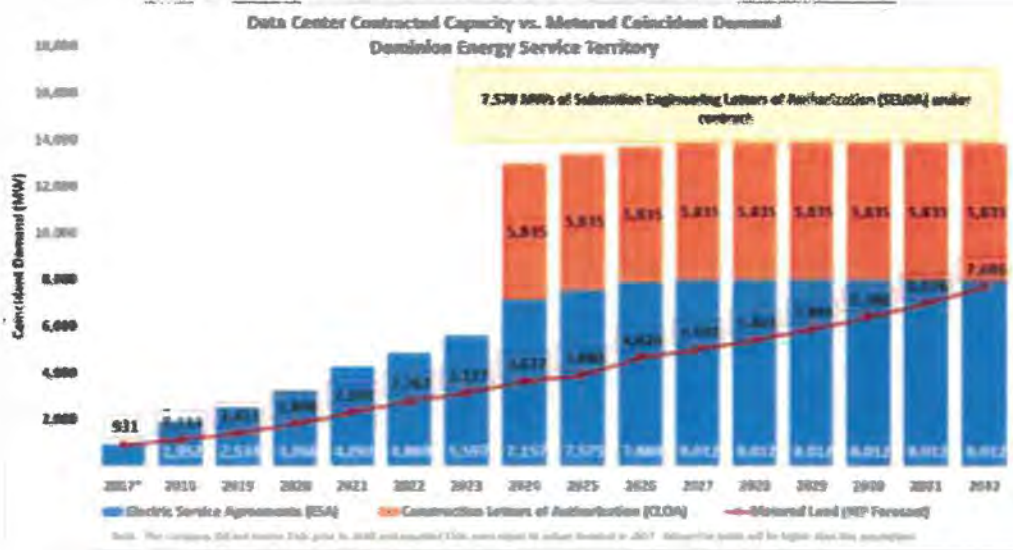
Notary Public

My Commission expires:



DOMINION VIRGINIA 2024 IRP*

Figure 2.1.7: Customer Contracts Executed, as of July 2024



**SCC Directed 2024 IRP Supplement Figure 2.1.1:
Comparison of Energy Forecast – DOM LSE**

	Energy (GWh)	
	2024 IRP	No Data Center Growth
2024	98,296	98,296
2025	99,307	97,761
2026	104,713	97,898
2027	107,693	98,127
2028	111,596	98,803
2029	115,058	98,955
2030	118,979	99,424
2031	122,949	100,011
2032	128,182	101,115
2033	132,684	101,515
2034	138,317	102,423
2035	144,476	103,484
2036	151,526	105,070
2037	158,049	105,844
2038	165,427	107,016
2039	172,999	108,329

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

EXHIBIT

tabbles

GIPLSF-3C



**Virginia Electric and Power
Company's Report of Its
2024 Integrated Resource Plan**

**Before the Virginia State
Corporation Commission and
North Carolina Utilities
Commission**

**Case No. PUR-2024-00184
Docket No. E-100, Sub 204**

Filed: October 15, 2024

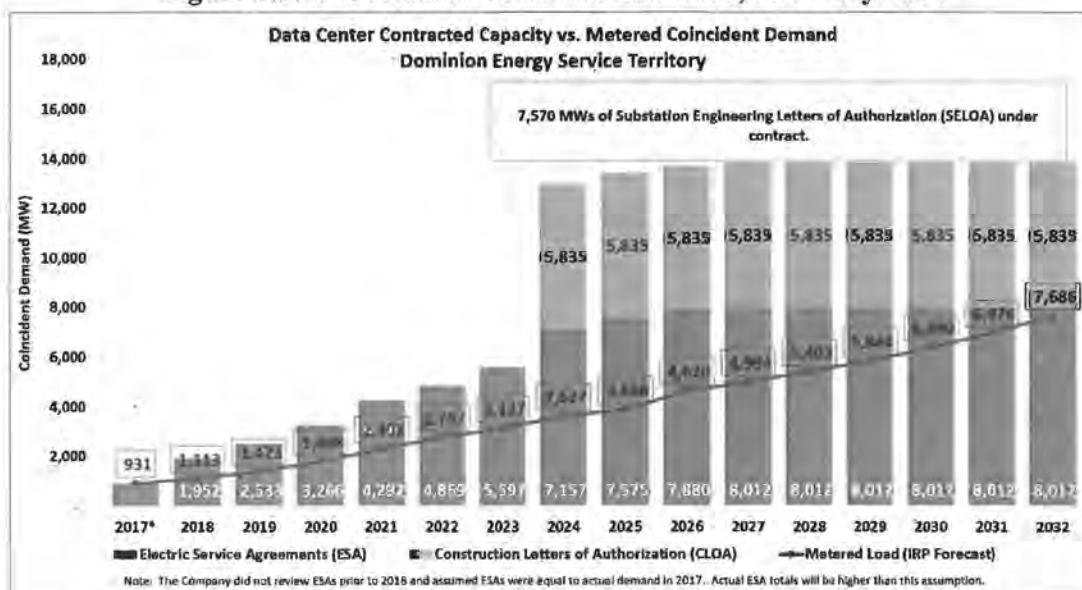
LED bulbs.⁹ The big drivers of current and future growth include migration to the cloud as businesses outsource information technology functions, smartphone technology and apps, 5G technology, digitization of data, and artificial intelligence (“AI”). From storing videos to hosting AI systems that allow consumers to create documents, web pages, music, and more, data centers serve the needs of the public every day.

Dominion Energy is confident in its Data Center Load Forecast. The Company uses a combination of historical metered data along with forward-looking customer intelligence, derived from long-term relationships with customers, to develop its Data Center Load Forecast. The Company provides a DOM LSE 15-year data center load forecast to PJM, who independently reviews and verifies before incorporating it into PJM’s own forecast.

Dominion Energy’s Data Center Load Forecast is informed and validated by existing contracts with customers. As projects progress, customers enter into a series of contracts with binding financial commitments. Dominion Energy regularly reviews this contractual approach to ensure that its Data Center Load Forecast reflects projects that will come to fruition.

Figure 2.1.7 illustrates customer contracts executed as of July 2024. These contracts are broken into (i) Substation Engineering Letters of Authorization (“SELOA”), (ii) Construction Letters of Authorization (“CLOA”), and (iii) Electric Service Agreements (“ESA”). As a customer moves from (i) to (iii), the cost commitment and obligation by the customer increases.

Figure 2.1.7: Customer Contracts Executed, as of July 2024



⁹ Based on typical performance, a light-emitting diode A19 lamp is roughly 92 lumens per watt and consumes about 10 watts.

for resource planning purposes. In addition, data center growth within the DOM LSE is validated by existing contracts with customers with binding financial commitments. The contracts that Dominion Energy currently has in hand supports the load forecast through 2032, if not beyond. As such, these customers are not just a number in a projection but rather are counting on us to provide them with reliable service.

Notwithstanding, and with respect to the Commission's desire for an expansive record, the Company has diligently undertaken the directed analysis as described in the October 11 Order and hereby presents the results as this SCC Directed 2024 IRP Supplement.

2.0 Sensitivity Modeling Input Assumptions

2.1 Load Forecast Assumptions

In order to model sensitivities to show projected data center load growth removed, as directed by the October 11 Order, new assumptions for the load forecast were created.

To show no data center load growth for the sensitivity analysis for energy, the Company used the DOM LSE load forecast and (1) froze the volume of energy attributable to data centers at the forecasted 2024 levels and (2) froze the proportion of Customer Choice data center customers at the forecasted 2024 levels and applied that to each forecast year.¹ SCC Directed 2024 IRP Supplement Figure 2.1.1 below shows the differences between the 2024 IRP energy forecast versus the directed "No Data Center Growth" energy forecast.

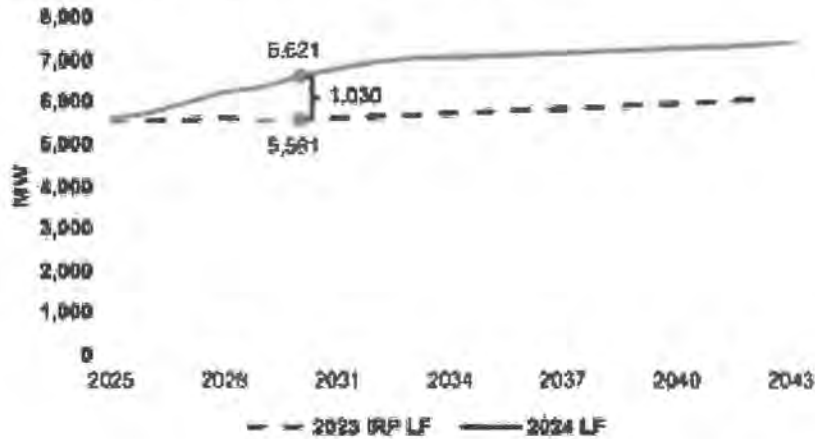
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Comparison of Energy Forecast – DOM LSE**

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2034	138,317	102,423
2035	144,476	103,484
2036	151,526	105,070
2037	158,049	105,844
2038	165,427	107,016
2039	172,999	108,329

¹ The Company also applied a factor to account for the impact of leap years.

SANTEE COOPER 2024 IRP UPDATE*

Figure 3. Forecast Winter Peak Demand



Electric Load Forecast Overview

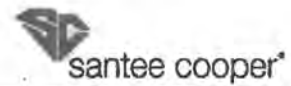
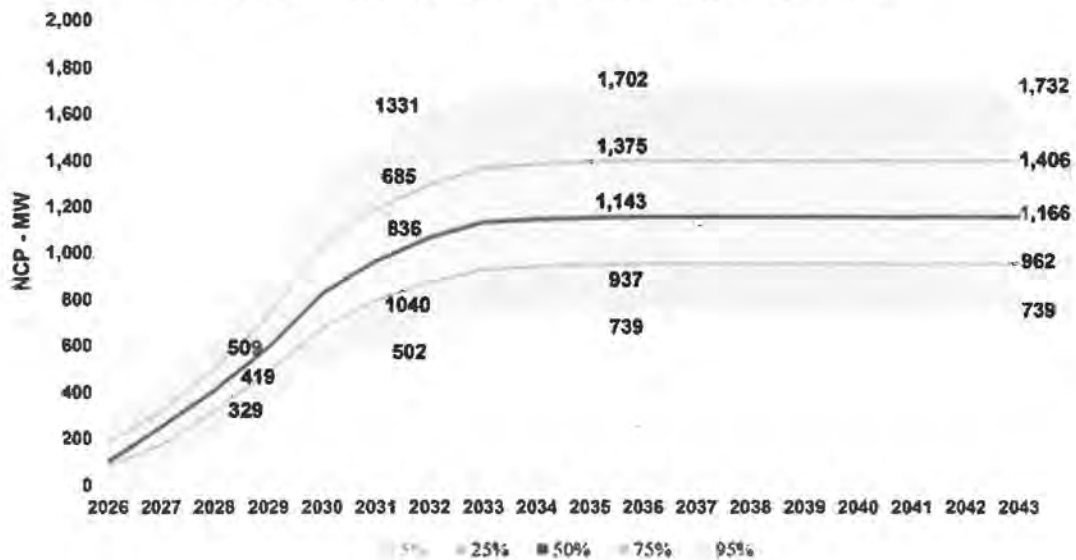


Figure 8. Range of Projected Potential New Large Loads



*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

Electric Load Forecast Overview

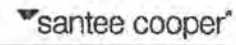


Table 6. Forecasted System Peak Demand (Winter MW)

Year	Direct-Served Residential and Commercial ¹⁵	Direct-Served Industrial	Municipal & Off-System	Central	Potential Large Load	Total	High Case	Low Case
2024	974	707	184	3,709	0	5,573	5,633	5,508
2025	980	743	186	3,705	0	5,615	5,724	5,116
2026	987	758	160	3,747	93	5,745	6,106	5,132
2027	994	759	147	3,855	243	5,998	6,383	5,211
2028	1,002	759	150	3,941	398	6,251	6,710	5,282
2029	1,010	759	36	4,016	550	6,371	7,017	5,268
2030	1,017	759	35	4,048	761	6,621	7,504	5,350
2031	1,025	759	35	4,078	909	6,807	7,718	5,373
2032	1,034	759	35	4,106	1,040	6,975	7,954	5,402
2033	1,042	759	35	4,128	1,086	7,050	8,091	5,400
2034	1,050	759	35	4,148	1,086	7,078	8,230	5,398
2035	1,057	759	35	4,171	1,086	7,109	8,331	5,398
2036	1,064	759	35	4,201	1,086	7,145	8,443	5,405
2037	1,071	759	35	4,228	1,086	7,179	8,554	5,410
2038	1,078	759	34	4,257	1,086	7,215	8,670	5,416
2039	1,086	759	34	4,287	1,086	7,252	8,794	5,424
2040	1,092	759	34	4,320	1,086	7,292	8,923	5,434
2041	1,098	759	34	4,352	1,086	7,330	9,052	5,443
2042	1,104	759	34	4,390	1,086	7,373	9,190	5,457
2043	1,110	759	30	4,429	1,086	7,415	9,331	5,468

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Santee Cooper

Integrated Resource Plan

2024 Update



Executive Summary

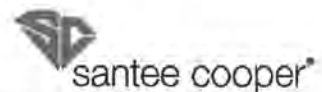
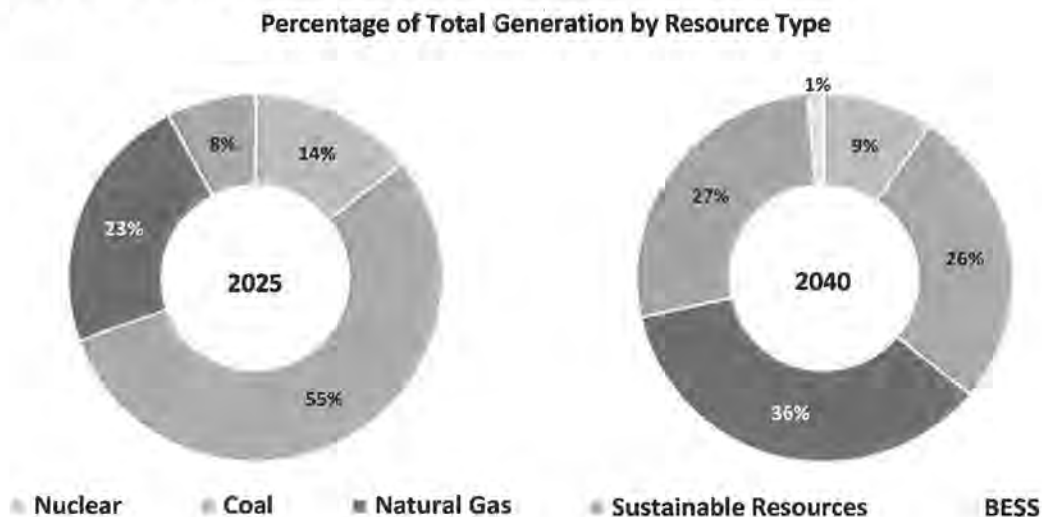


Figure 2. Projected Change in Energy by Fuel Type



- Instead of being largely reliant on coal, the portfolio would rely on a diverse mix of natural gas, sustainable, and coal resources, which reduces risk to customers.
- The resource options offer flexibility to further adjust as conditions change or if customer demand for electricity is higher or lower than currently projected.

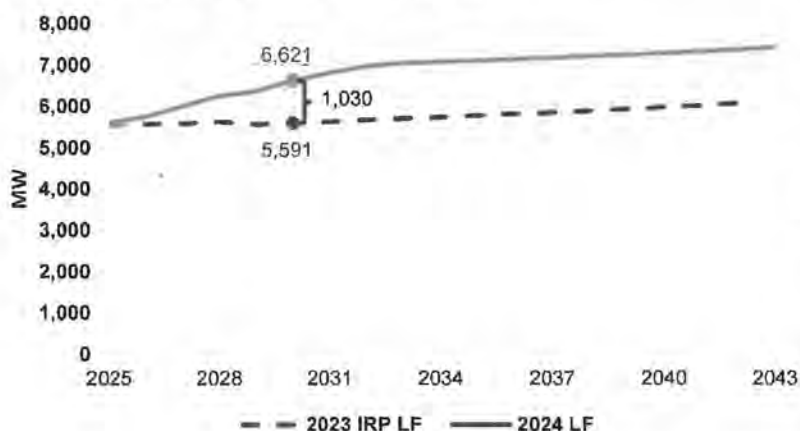
Finally, the resource changes are appropriate irrespective of the outcome of legal challenges to the EPA's recently published final rule regulating GHG emissions.

KEY DRIVERS AND CONSIDERATIONS

2024 LOAD FORECAST

The load forecast is a key assumption for resource evaluations, and Santee Cooper and Central work collaboratively to develop the Combined System load forecast. Since the development of the load forecast used for the 2023 IRP, Santee Cooper and Central's member cooperatives have received multiple inquiries for potential service from industrial and other customers, many with

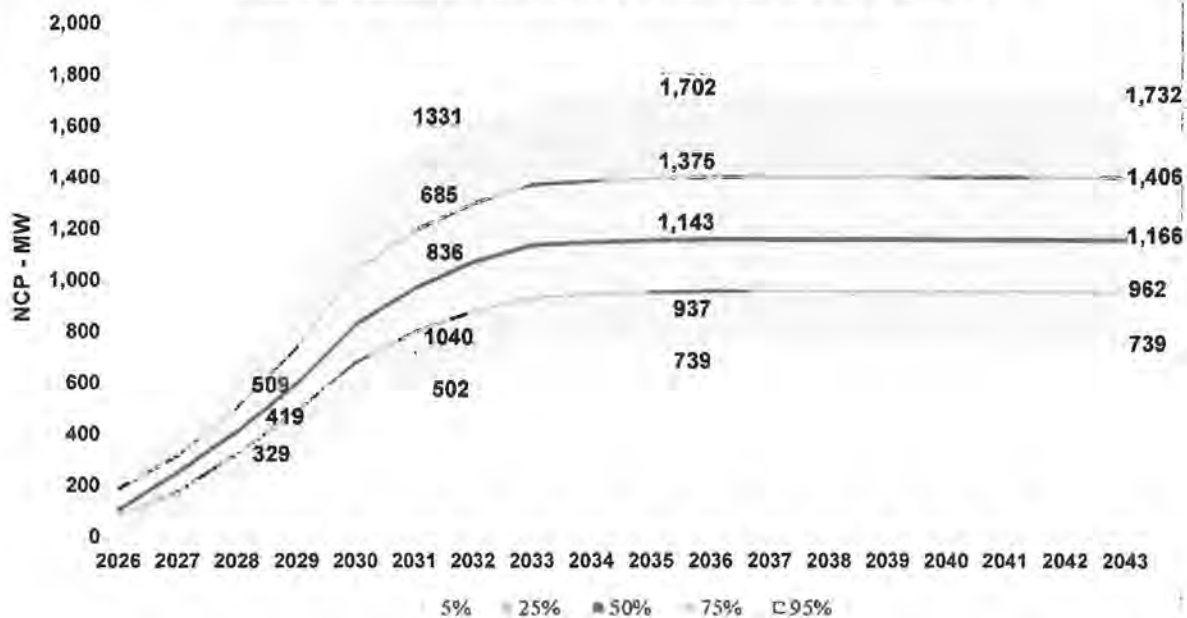
Figure 3. Forecast Winter Peak Demand



substantial new peak demand and energy requirements. This trend is consistent with observations from utilities in many parts of the country, including the Southeast. The Commission recognized this trend and ordered Santee Cooper to "engage stakeholders to discuss the additional economic development in the state and how best to

Electric Load Forecast Overview

Figure 8. Range of Projected Potential New Large Loads



For purposes of the High Case scenario, Santee Cooper used the 95th percentile outcome, which reflected 525 MW of additional new large loads by 2043 for a total of 1,592 MW of new large loads (on a coincident peak demand basis). For the Low Case scenario, Santee Cooper used the results near the minimum stochastic outcome, which represents 200 MW of new large loads. Furthermore, the Low Case includes a 400 MW reduction representing the loss of a very large, or several medium to large, industrial customers in Santee Cooper or Central territory. These two adjustments net to a 200 MW reduction in industrial and new large loads. The Low Case results reflected a decrease of 1,295 MW compared to the Base Case.

SANTEE COOPER SYSTEM LOAD FORECAST

The 2024 Load Forecast Base Case reflects the growth that has been occurring on the system. Continued population growth and rapid economic development throughout the state leads to increased energy sales from Santee Cooper's direct served customers and Central. Santee Cooper's 2043 winter CP demand is forecasted to be approximately 1,300 MW higher in the 2024 Load Forecast compared to the 2023 IRP with an average annual growth rate of 1.4 percent compared to an expected growth rate of 0.5 percent in the 2023 IRP. Table 6 presents the forecasted winter peak demand, and Table 7 presents annual energy sales for the system from 2024-2043, including transmission and distribution losses and excluding future demand side management and energy efficiency.

Electric Load Forecast Overview

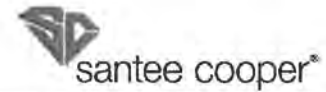


Table 6. Forecasted System Peak Demand (Winter MW)

Year	Direct-Served Residential and Commercial ¹⁵	Direct-Served Industrial	Municipal & Off-System	Central	Potential Large Load	Total	High Case	Low Case
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2025	980	743	186	3,705	0	5,615	5,724	5,116
2026	987	758	160	3,747	93	5,745	6,106	5,132
2027	994	759	147	3,855	243	5,998	6,383	5,211
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2037	1,071	759	35	4,228	1,086	7,179	8,554	5,410
2038	1,078	759	34	4,257	1,086	7,215	8,670	5,416
2039	1,086	759	34	4,287	1,086	7,252	8,794	5,424
2040	1,092	759	34	4,320	1,086	7,292	8,923	5,434
2041	1,098	759	34	4,352	1,086	7,330	9,052	5,443
2042	1,104	759	34	4,390	1,086	7,373	9,190	5,457
2043	1,110	759	30	4,429	1,086	7,415	9,331	5,468

¹⁵ Gross of future demand side management/energy efficiency ("DSM/EE") related to Santee Cooper's retail customers but net of Central's DSM/EE.

DUKE 2023 CAROLINAS RESOURCE PLAN*

Table D-11: Adjustments in the Load Forecast for Large Site Developments in MWh

Year	DEC	DEP
2023	139,023	—
2024	711,032	525,627
2025	1,016,318	946,087
2026	1,504,031	1,288,761
2027	2,122,049	1,723,534
2028	2,931,801	2,120,269
2029	3,518,174	2,402,781
2030	4,104,546	2,765,064
2031	4,690,919	2,892,107
2032	5,277,291	2,892,107
2033	5,863,664	2,892,107
2034	5,863,664	2,892,107
2035	5,863,664	2,892,107
2036	5,863,664	2,892,107
2037	5,863,664	2,892,107
Avg. Annual Growth Rate	25.0%	13.0%

In summary, the size, scale and speed of economic development of mega-projects has dramatically increased over the past two years, such that a greater proportion of the portfolio is above the threshold where an explicit addition to the forecast is appropriate. Duke Energy has played a critical role in partnering with local and state economic development entities to ensure the successful recruitment of these highly competitive mega-projects to the DEC and DEP service areas. The Companies have seen specific success in the emerging EV sector to include vehicle manufacturing, battery production and associated supply chain along with "re-emerging" industries such as steel production, semi-conductors and large-scale data centers.

Table D-15: Electric Vehicles, EVs in Operation and Load Impacts – DEC

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2023	45,638	0.82%	25,518
2037	2,074,921	31.03%	7,380,537

Table D-16: Electric Vehicles, EVs in Operation and Load Impacts – DEP

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2023	31,231	0.94%	16,004
2037	1,282,364	31.80%	4,450,652

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

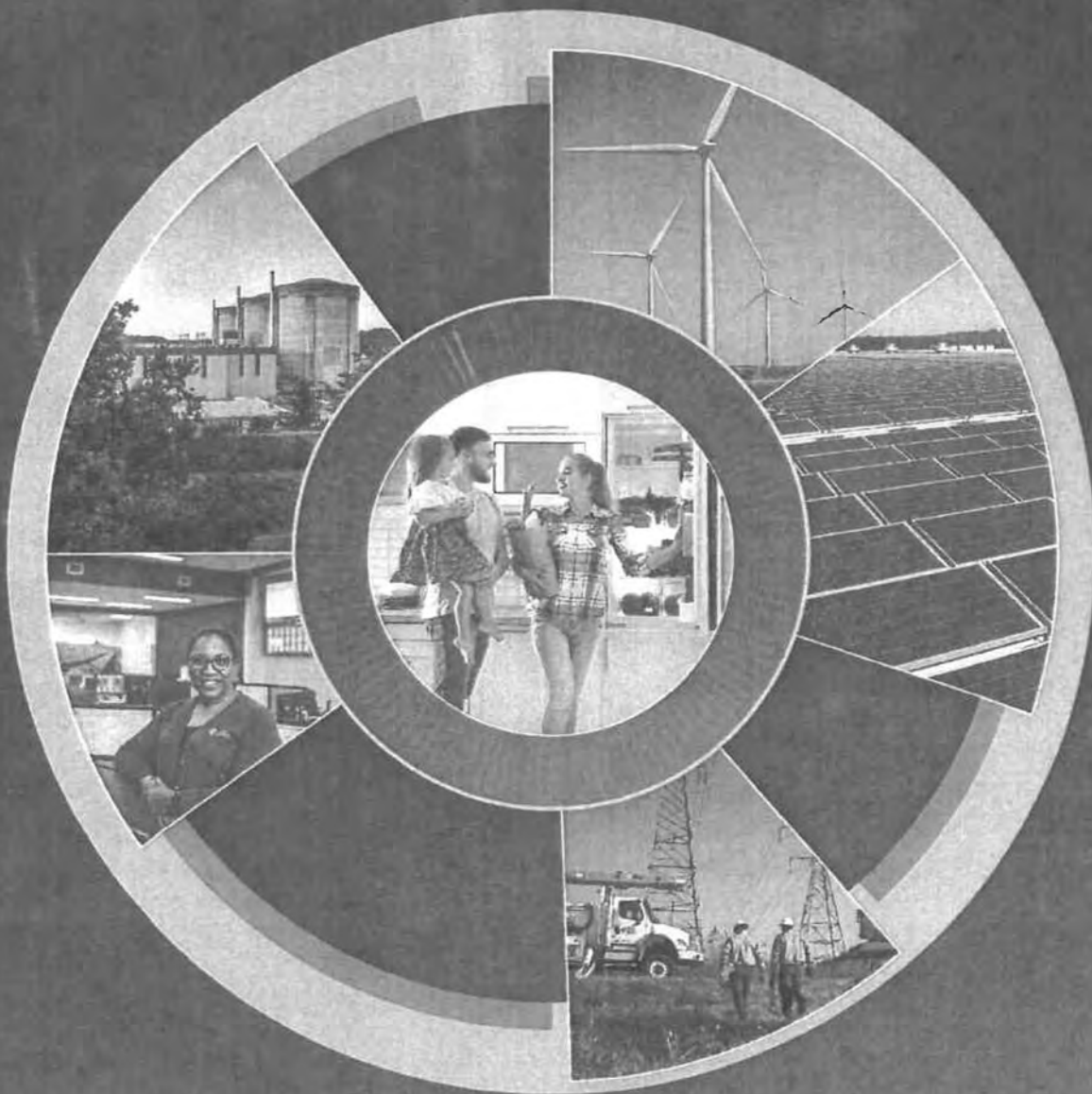
EXHIBIT

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GIPLSF-3E



2023 Carolinas Resource Plan



BUILDING A SMARTER ENERGY FUTURE®

Table D-11: Adjustments in the Load Forecast for Large Site Developments in MWh

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2029	3,518,174	2,402,781
2030	4,104,546	2,765,064
2031	4,690,919	2,892,107
2032	5,277,291	2,892,107
2033	5,863,664	2,892,107
2034	5,863,664	2,892,107
2035	5,863,664	2,892,107
2036	5,863,664	2,892,107
2037	5,863,664	2,892,107
Avg. Annual Growth Rate	25.0%	13.0%

In summary, the size, scale and speed of economic development of mega-projects has dramatically increased over the past two years, such that a greater proportion of the portfolio is above the threshold where an explicit addition to the forecast is appropriate. Duke Energy has played a critical role in partnering with local and state economic development entities to ensure the successful recruitment of these highly competitive mega-projects to the DEC and DEP service areas. The Companies have seen specific success in the emerging EV sector to include vehicle manufacturing, battery production and associated supply chain along with "re-emerging" industries such as steel production, semi-conductors and large-scale data centers.

Rooftop Solar

BTM or rooftop solar or solar photovoltaic ("PV") is currently available in the Carolinas. The forecast used in the Resource Plan reflects impacts from approved rates in the Carolinas as of January 1, 2023, which are decremented directly from the initial Itron model output. Table D-12 below summarizes the number of current customers enrolled in these programs for both the DEC and DEP service areas by customer class, as well as the total energy in MWh forecasted to be generated from BTM solar generation on customer sites in 2023.

Table D-15: Electric Vehicles, EVs in Operation and Load Impacts – DEC

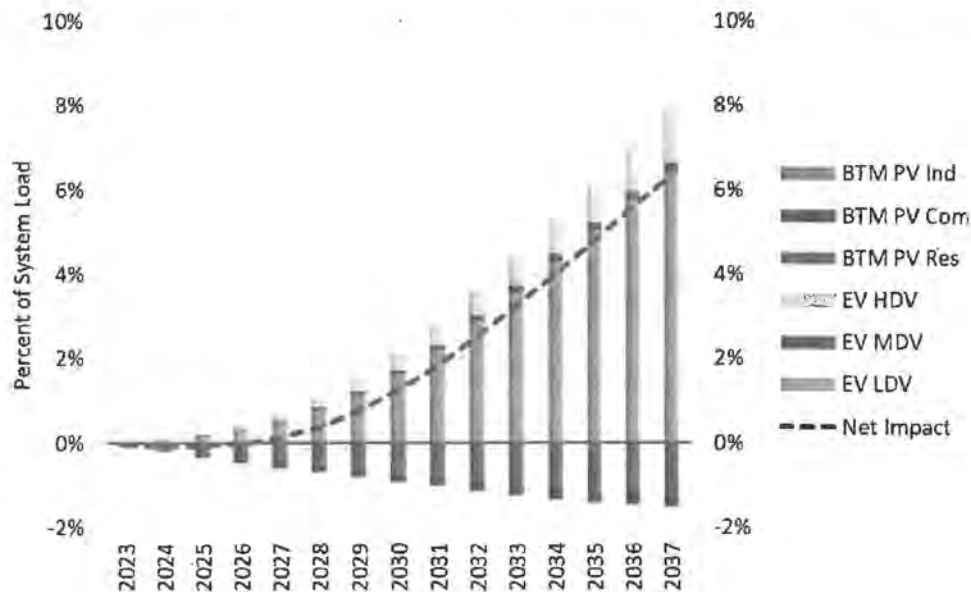
Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2023	45,638	0.82%	25,518
2037	2,074,921	31.03%	7,380,537

Table D-16: Electric Vehicles, EVs in Operation and Load Impacts – DEP

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2023	31,231	0.94%	16,004
2037	1,282,384	31.80%	4,450,652

Net Impact of Rooftop Solar and Electric Vehicles

Figure D-3 through Figure D-8 below illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon. The load forecast is incremented by these projections. More detailed discussion of both parts can be found in their own respective appendices.

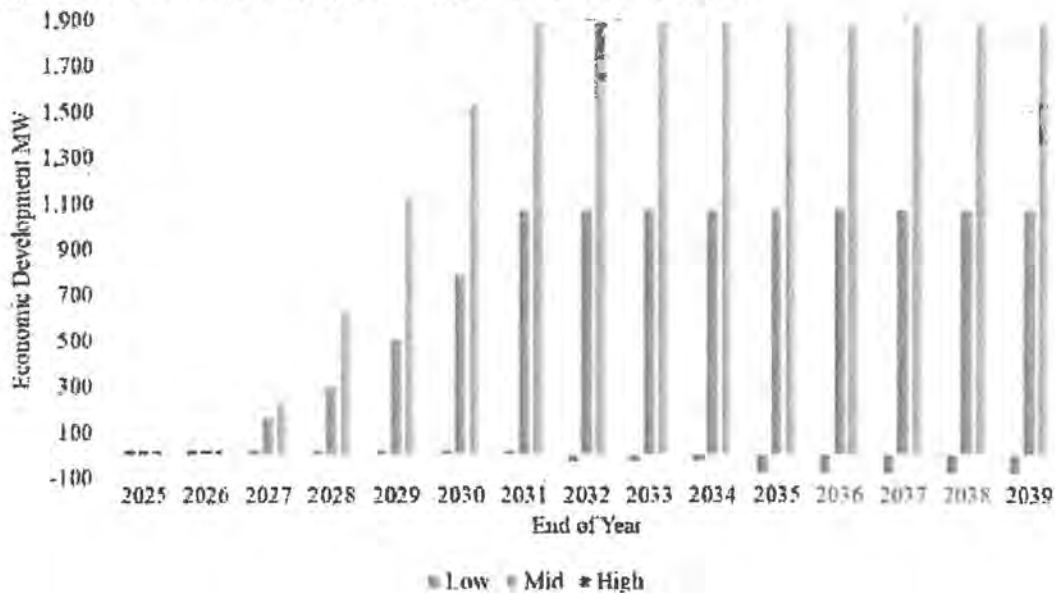
Figure D-3: Percent Impact of PV and EV on Annual Load in DEC, Net New from 2023

LG&E AND KU 2024 RESOURCE PLAN*

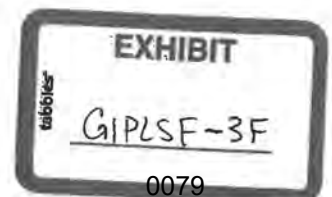
Table 5-2: 2024 IRP Load Forecast Scenarios—Key Differences

Load Scenario	Data Centers in 2032	Distributed Generation in 2032	Energy Efficiency, CVR, AML, and Other Energy Reductions in 2032 ²¹
Low	0 MW	275 MW	2,150 GWh
Mid	1,050 MW	150 MW	1,500 GWh
High	1,750 MW	125 MW	700 GWh

Figure 5-8: Economic Development Growth Projections (GWh)



*Summary of selected screenshots, compiled by counsel for GIPL and Southface.



**2024 Joint Integrated
Resource Plan of
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Company and Kentucky
Utilities Company**



PPL companies

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analysis period. This is particularly significant for the cost of solar, which is projected in nominal terms to decrease by more than 30% by 2035. The Companies' Resource Assessment tests this assumption by evaluating a sensitivity where the cost of solar is assumed to escalate slowly from the beginning of the analysis period.

5.(3) Energy Requirements ("Load") Forecasts

In accordance with 807 KAR 5:058 Section 7(3), the Companies developed a base load forecast (called the "Mid" forecast in this IRP), as well as High and Low forecasts of energy requirements to evaluate resource planning decisions under multiple load scenarios.

The Companies' load forecasting process continues to account for important macroeconomic data, customer usage history and trends, and other energy usage drivers such as projected end-use efficiency and saturation data (e.g., the saturation of high-efficiency heat pumps for residential customers).

Of particular importance to this IRP is economic development activity. Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. The evolution of economic development projects puts more emphasis on energy availability than ever before. Site selection consultants indicate that energy availability and cost are among the top ten most important factors in site selection over the last two years, and energy availability was tied for first on the list in 2022. Energy availability is a necessity to compete for major projects in primary metals manufacturing, indoor agriculture, battery production, and now data centers. Energy-intensive data centers are crucial to consumers, businesses, and the safety and security of our nation. They support critical business applications, store valuable business and personal data, keep data safe from threats, and serve as a foundation for modern business and government applications.

Therefore, potential new data centers are a key load forecast driver in this IRP. To model the effects of such large potential loads, as well as other important items such as distributed generation and energy efficiency, the Companies created three load forecast scenarios, as shown in Table 5-2 below, to study what the lowest-cost portfolios might be across a reasonable range of possible future load scenarios:

Table 5-2: 2024 IRP Load Forecast Scenarios—Key Differences

Load Scenario	Data Centers in 2032	Distributed Generation in 2032	Energy Efficiency, CVR, AMI, and Other Energy Reductions in 2032²¹
Low	0 MW	275 MW	2,150 GWh
Mid	1,050 MW	150 MW	1,500 GWh
High	1,750 MW	125 MW	700 GWh

²¹ Includes energy reductions from customer-initiated energy efficiency improvements, AMI-related conservation voltage reduction ("CVR") and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan and new programs beyond 2030.

- **The Companies' system is now consistently dual-peaking.** Figure 5-7 above shows that the Companies' system peaks routinely occur in the winter, and the highest peaks in the last ten years have all occurred in the winter. This means the Companies must plan to serve peak loads not only on sunny summer days when solar is maximally producing, but also during cold, non-daylight winter hours. Importantly, the Companies' customers tend to consume more than half of their daily energy during non-daylight hours in the winter, as well as more than 30% during non-daylight hours in the summer. Therefore, the Companies' resource planning must consider not just peak load conditions but also total energy needs in all hours and seasons.
- **All the load forecasts assume significant amounts of energy-reducing measures, including from the Companies' DSM-EE Programs and distributed generation.** For example, as shown in Table 5-2 above, the Companies' Mid load forecast includes nearly 1,500 GWh annually of energy reductions by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan and new programs beyond 2030. These reductions are in addition to significant reductions observed historically from customers' actions to use electricity more efficiently. The Mid load forecast further assumes 150 MW of installed distributed solar capacity by 2032. These items have a non-trivial impact on the Companies' load forecast.

Key Forecast Assumptions and Uncertainties

The following is a discussion of key energy requirement forecast assumptions and uncertainties. Note that the weather and cost of service assumptions do not change among the three load forecast scenarios.

1. Economic Development

As noted above and discussed at length in Section 7, Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. Of particular importance to this IRP is potential data center load. Data centers tend to be large, with each potentially ranging from several hundred megawatts to one gigawatt or more, and they have exceptionally high load factors, i.e., in the range of 95%.

The IRP considers three economic development load growth scenarios to address this uncertainty and opportunity. The Mid scenario assumes 1,050 MW of data center load by 2032 and another relatively small economic development project. The High scenario assumes 1,750 MW of data center load in addition to the smaller project plus the second phase of the Blue Oval SK ("BOSK") electric vehicle battery production facility. Figure 5-8 compares the three economic development scenarios the Companies contemplated. The Mid and High scenarios account for small portion of data center load growth projections for the U.S. as a whole.²³ In the Low scenario, zero data centers

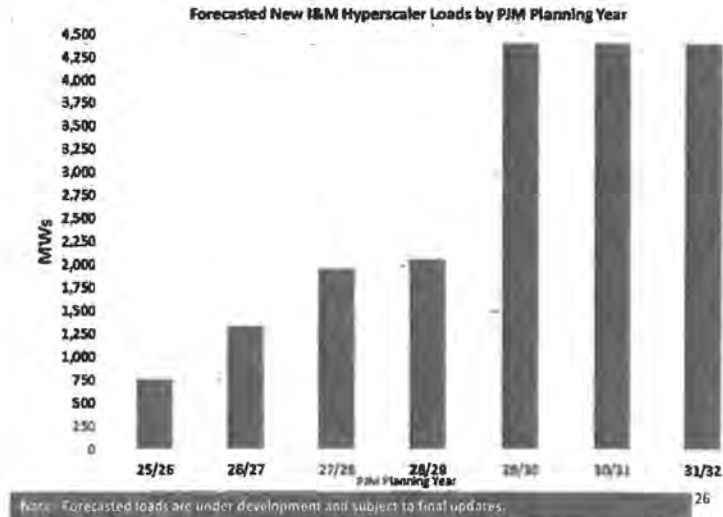
²³ The Mid scenario represents 4.2% of data center load growth in the U.S. from a recent Newmark study (<https://www.nmrk.com/storage-e-nmrk/uploads/documents/2023-U.S.-Data-Center-Markets.pdf>) and 9.4% of EPRI's Moderate growth projection (<https://restservice.epri.com/publicdownload/000000003002028905/0/Product>). The High scenario represents 7.5% of EPRI's High growth projection and only 4.3% of their Higher growth projection.

INDIANA MICHIGAN POWER 2024 INDIANA IRP*



Considerations for New Hyperscaler Loads (HSL) in IRP

- New load forecasted to more than double the current peak load served by I&M and occur over the next five to six years
- AEP and PJM will identify any transmission upgrades necessary to serve the new load
- I&M will utilize short-term existing PJM resources that provide a bridge to a long-term generation resource portfolio
- The long-term generation portfolio will be optimized through the IRP process to identify the best mix of resources to serve all Indiana customers
- Additional post-2030 HSL will be considered as part of a sensitivity (phase 2 load)



*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

EXHIBIT

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An **AEP** Company

INDIANA INTEGRATED RESOURCE PLANNING REPORT

to the:

Indiana Utility Regulatory Commission

Appendix – Volume 4

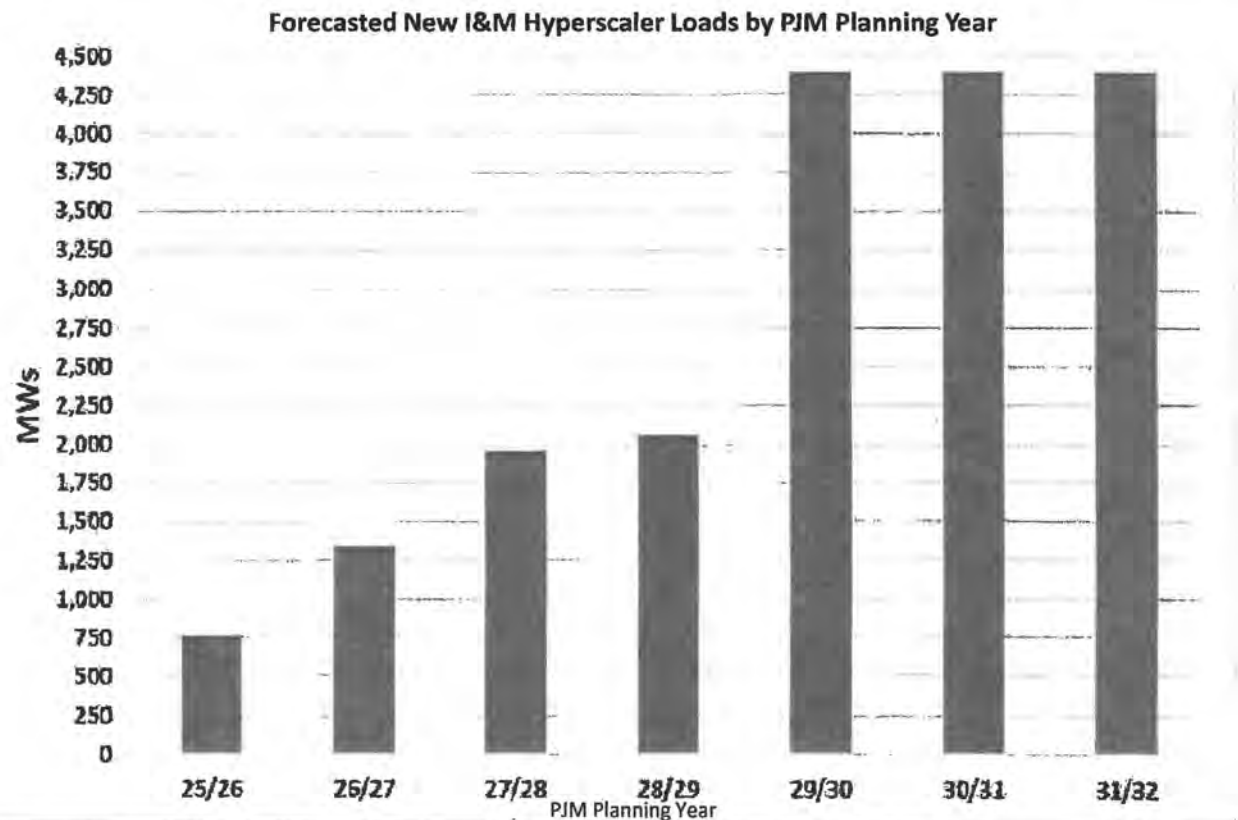
Submitted Pursuant to:

Commission Rule 170 IAC 4-7

March 28, 2025

Considerations for New Hyperscaler Loads (HSL) in IRP

- New load forecasted to more than double the current peak load served by I&M and occur over the next five to six years
- AEP and PJM will identify any transmission upgrades necessary to serve the new load
- I&M will utilize short-term existing PJM resources that provide a bridge to a long-term generation resource portfolio
- The long-term generation portfolio will be optimized through the IRP process to identify the best mix of resources to serve all Indiana customers
- Additional post-2030 HSL will be considered as part of a sensitivity (phase 2 load)



Note: Forecasted loads are under development and subject to final updates.

PUBLIC DISCLOSURE

Attachment 6.0-2: Winter Coincident Demand with Adjustments (MW)

Calendar Based Budget 2025

Year	Unadjusted Class Coincident Demand					Unadjusted Coincident Demand	Adjustments (MW)		Adjusted Peak Demand
	Res	Com	Ind	Gov Lighting	MARTA		CoGen	DSM	
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	15,992
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	16,264
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	16,892
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	18,334
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	20,320
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	22,168
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	23,612
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	24,469
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	24,900
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	25,213
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	25,451
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	25,653
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	25,768
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	25,987
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	26,216
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	26,605
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	26,917
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	27,295
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	27,687
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	28,118
2044	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	28,544



BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

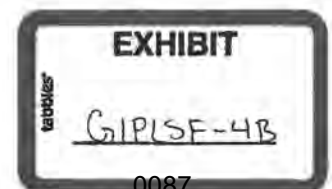
**GEORGIA POWER COMPANY
DOCKET NO. 56002**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2025 Integrated Resource Plan ("2025 IRP"), filed in Docket No. 56002, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 1, which contains certain information regarding the Company's demand-side plans, load and energy forecast data, reserve margin, unit retirements, unit upgrades, proprietary planning processes, wholesale-to-retail offers, and Critical Energy Infrastructure Information ("CEII") in the form of drawings/schematics of dam infrastructure of the Company's hydro facilities (collectively, the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the trade secret portions of the Information contain competitively sensitive cost information related to optimal reserve margins and reserve margin scenarios, processes and data used by Georgia Power in analyzing resource addition and retirement schedules, demand-side program details, financial assumptions and other confidential details. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. With this competitive advantage, Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers. The Information also includes sensitive details concerning Georgia Power's infrastructure that must be protected from public disclosure in the interests of system security and reliability. Such portions of the Information contain Critical Energy Infrastructure Information as defined by the Code of Federal Regulations Section 388.113.

Certain trade secret portions of the Information provided includes detailed forecasted information regarding the Company's future energy and demand growth, which could be used to determine the Company's short-term capacity needs. If revealed to the public, a generation wholesaler or power marketer could use the trade secret portions of the Information to tailor proposals with the intention of pricing products in a manner that would undermine the Company's market position. Such disclosure could unfairly allow competitors to manipulate the wholesale market and ultimately harm retail customers through higher rates and less reliability. Lastly, the Company's competitors are not required to file their respective forecast information.



The trade secret portions of the information described above is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company affiliate personnel are granted access to the trade secret portions of the Information. Those personnel receive access on a "need to know" basis only. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 1 of the Company's 2025 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).



Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 27 day of January, 2025.



Notary Public

My Commission expires:



PUBLIC DISCLOSURE
Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
Hearing Request Set Number 1

HR-1-2

Information requested by: Georgia Interfaith Power & Light and Southface Energy Institute – Jennifer Whitfield

Question:

Q Georgia Power, the Independent Evaluator, and Staff have agreed to provide the megawatts by fuel type of the resources that are still in the Competitive Tier of the All-Source RFP.

Response:

Please refer to the table below that identifies a summary of the resources included in the Competitive Tier of the All-Source RFP by fuel type and megawatts ("MW").

GPC All-Source Capacity RFP for Need Years 2029-2031 – Competitive Tier	
Fuel Type	Exclusive MW (Summer)
REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED
Total	REDACTED



BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NOS. 56002 & 56003**

Direct Hearing Request HR-1-2

**BASIS FOR THE ASSERTION THAT THE
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power Company's 2025 Integrated Resource Plan filed in Docket No. 56002 ("2025 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 56003 ("2025 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to Direct Hearing Request 1-2 ("Response"). In the Response, the Company has provided specific information on the Company's Request for Proposals ("RFP"). All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains information regarding proposals submitted in the Company's RFP. Should this information be shared publicly, it could lead to an artificial pricing floor in future RFP bids, which would result in the Company having to pay a price higher than it would have otherwise paid on a level playing field. This would also lead to higher prices for customers. In addition, public dissemination of the Information would compromise the Company's ability to negotiate the best cost resources in connection with these or future proposals. Finally, competitors of the Company are not generally required to disclose similar information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.



PUBLIC DISCLOSURE

Table 5: B2025 Technology Cost and Performance Summary

Technology	Winter Capacity (MW)	ELCC	Average Heat Rate (Btu/kWh)	Round Trip Efficiency	Fixed Capacity Factor	Overnight Cost (2024\$/kW)	Recurring Fixed Cost ² (2024\$/kW-yr)	Variable O&M (\$/MWh)	Asset Life (Yrs)
Natural Gas Combined Cycle (NGCC)	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
NGCC with Local CCS	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
NGCC with Distant CCS	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combustion Turbine with SCR, Oil Winter (CT w SCR)	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Solar Photovoltaic (PV) - Single Axis Tracker (SAT)	REDACTED	0%			REDACTED	REDACTED	REDACTED		REDACTED
Onshore Wind Power	REDACTED	35%			REDACTED	REDACTED	REDACTED		REDACTED

² Recurring fixed costs include Fixed O&M, Maintenance Capital, and Natural Gas Firm Transportation.



PUBLIC DISCLOSURE

Technology	Winter Capacity (MW)	ELCC	Average Heat Rate (Btu/kWh)	Round Trip Efficiency	Fixed Capacity Factor	Overnight Cost (2024\$/kW)	Recurring Fixed Cost ² (2024\$/kW-yr)	Variable O&M (\$/MWh)	Asset Life (Yrs)
Lithium-ion Battery Energy Storage System (BESS) - 4 Hr	REDACTED REDACTED	0-3000 MW : 95% 3001-6000 MW : 75% 6001-9000 MW : 50% 9001+ MW : 25%		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Medium Duration Energy Storage System	REDACTED REDACTED	100%		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Nuclear (AP-1000)	REDACTED	100%				REDACTED	REDACTED		REDACTED

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 56002**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2025 Integrated Resource Plan ("2025 IRP"), filed in Docket No. 56002, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 2, which contains certain information regarding the company's financial data, proprietary planning processes, technology screening assumptions, technology and resource cost information, economic analyses, environmental compliance costs, including projected and current cost estimates for coal combustion residual asset retirement obligation ("CCR ARO") ash pond closure and landfill projects, Critical Energy Infrastructure Information ("CEII") related to the Company's blackstart facilities, and other data of the Company (collectively, the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the trade secret portions of the Information contain competitively sensitive cost information related to available technology options, processes and data used by Georgia Power in analyzing resource addition schedules, financial data used in the Company's forecasting, and other confidential details. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. With this competitive advantage, Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers. The Information also includes sensitive details concerning Georgia Power's electric system infrastructure that must be protected from public disclosure in the interests of system security and reliability. Such portions of the Information contain CEII as defined by the Code of Federal Regulations Section 388.113.

The trade secret portions of the Information contained herein also include details concerning Georgia Power's projected environmental capital investments, cost data, and analyses, all of which have economic value that could be inappropriately leveraged by competitors, vendors, or other persons. Specifically, the trade secret portions of the Information contain competitively sensitive details on the site specific and CCR unit specific costs the Company is expected to incur to close its ash ponds and landfills as well as the timing. Publicly disclosing these costs would allow bidders and vendors to tailor proposals according to the Company's expected costs, setting an artificial floor on bidding to the detriment and harm of the Company and its customers. Disclosure of the trade secret portions of the Information could prevent the Company from adequately soliciting and obtaining the best cost estimates for future consulting work and harm the Company's efforts to

EXHIBIT

tabular
GIPLSF-6B

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obtain optimal pricing in current or future negotiations. In addition, the Company's competitors are not generally required to disclose similar information, and to require the Company to do so would put it at an economic disadvantage.

Additionally, certain trade secret portions of the Information contain proprietary cost data and analysis prepared on the Company's behalf by outside consultants. These studies were prepared by paid consultants of the Company at a significant cost and thus derive economic value from not being generally known. To allow competitors to access information related to and contained in these studies would economically harm the Company in that competitors would be able to benefit from the information and analysis contained in the studies without similarly being required to expend similar resources for the analysis and intelligence.

The trade secret portions of the Information are subject to substantial procedures to maintain their secrecy. Only select Georgia Power and Southern Company personnel are granted access to the trade secret portions of the Information. Those personnel receive access only on a "need to know" basis. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 2 of the Company's 2025 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).



Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 27 day of January, 2025.



Notary Public

My Commission expires:



LG&E AND KU 2024 RESOURCE PLAN*

Table 6-4: Capital Costs (\$/kW) and Sum of Capital and Non-Fuel O&M (\$/kW-yr) for Selected Resources

Resource	2021 IRP 2022 \$		2022 CPCN ³⁷ 2026/2027 \$		2024 IRP 2030 \$	
	Capital (\$/kW)	Capital + Non-Fuel O&M (\$/kW-yr)	Capital (\$/kW)	Capital + Non-Fuel O&M (\$/kW-yr)	Capital (\$/kW)	Capital + Non-Fuel O&M (\$/kW-yr)
SCCT	885	127	679	83	1,636	182
NGCC	1,008	140	1,048	117	2,121	222
Solar No ITC/PTC	1,305	126	1,462	136	1,902	183
Solar with ITC/PTC		101		90		133
4-hr BESS No ITC	1,274	172	2,159	300	2,049	265
4-hr BESS with ITC		N/A		138		138

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.



**2024 Joint Integrated
Resource Plan of
Louisville Gas and Electric
Company and Kentucky
Utilities Company**



PPL companies

Case No. 2024-00326

Volume I

Table 6-4: Capital Costs (\$/kW) and Sum of Capital and Non-Fuel O&M (\$/kW-yr) for Selected Resources

Resource	2021 IRP 2022 \$		2022 CPCN ³⁷ 2026/2027 \$		2024 IRP 2030 \$	
	Capital (\$/kW)	Capital + Non-Fuel O&M (\$/kW-yr)	Capital (\$/kW)	Capital + Non-Fuel O&M (\$/kW-yr)	Capital (\$/kW)	Capital + Non-Fuel O&M (\$/kW-yr)
SCCT	885	127	679	83	1,636	182
NGCC	1,008	140	1,048	117	2,121	222
Solar No ITC/PTC	1,305	126	1,462	136	1,902	183
Solar with ITC/PTC		101		90		133
4-hr BESS No ITC	1,274	172	2,159	300	2,049	265
4-hr BESS with ITC		N/A		138		138

Generation Capacity Needs

Table 6-5 contains a summary of winter and summer total reserve margins and capacity needs from the 2021 IRP compared to the 2024 IRP.

When the 2021 IRP was filed, the resource plan reflected the retirement of Mill Creek 1 in 2024 and the small-frame SCCTs in 2025. Because Mill Creek 1 and 2 cannot operate simultaneously during the ozone season due to NO_x limits, one of the units (300 MW) was assumed to be unavailable in the summer from 2022 to 2024. The Rhudes Creek solar facility (100 MW nameplate) was assumed to come online in 2023 and an additional 160 MW of Green Tariff Option 3 solar was added in 2025. None of this capacity was available to serve winter peak because the Companies' winter peak occurs at night. Approximately 79% of the new solar capacity was assumed to be available to serve summer peak. The Companies' target reserve margin range was 17 to 24 percent in the summer and 26 to 35 percent in the winter. Based on those reserve margin ranges, the Companies anticipated being capacity sufficient until at least 2028, when the Companies would have a small reserve margin deficit in the summer and a larger reserve margin deficit in the winter after the assumed retirements of Mill Creek 2 and Brown 3.

The 2024 IRP continues to reflect the retirement of Mill Creek 1 in 2024 and the small-frame SCCTs in 2025 but excludes the Rhudes Creek solar facility and the Green Tariff Option 3 solar that were included in the 2021 IRP. The 2024 IRP also includes the retirement of Mill Creek 2 in 2027 and the addition of the Company-owned resources approved in the 2022 CPCN Order including Mill Creek 5, the Brown Battery Energy Storage System, Mercer County Solar, Marion County Solar, and demand response programs from the Companies' 2024-2030 DSM-EE Program Plan. A capacity increase on Carle Run 7 in 2026 to reach the full potential of its 2024 turbine upgrades is also assumed. The 2024 IRP's minimum reserve margin targets are 23% in summer and 29% in winter based on limiting loss-of-load expectation ("LOLE") to one day in 10 years.

³⁷ 2022 CPCN values reflect costs as filed. The Companies provided an update to NGCC capital costs of \$1,466/kW based on bids received in their response to the Joint Intervenor's Post-Hearing Data Request 4.1 in Case No. 2022-00402.

SANTEE COOPER 2024 IRP UPDATE*



Major Modeling Assumptions

Table 13. Fossil-Fueled and Nuclear Resource Option Parameters

Technology	Net Capacity (MW; Avg. Ambient)	Base Year Capital Costs (\$/kW)	Fixed O&M Cost (\$/kW-yr.)	Variable O&M Cost (\$/MWh)	Full Load Heat Rate (Btu/kWh)	Year First Available
Combined Cycle (2x1; H-class)	1,264	1,335	5.16	2.85	6,116	2031
Combined Cycle (Half of a 2x1; H-class; i.e., Shared Resource)	632	1,335	5.16	2.85	6,116	2031
Combined Cycle (1x1; H-class)	630	1,700	7.77	2.85	6,136	2031
Combined Cycle (1x1; F-class)	357	2,626	11.75	3.30	6,668	2031
Combustion Turbine (H-class)	402	1,674	5.10	9.60	9,386	2031
Combustion Turbine (F-class)	230	1,848	8.18	8.97	10,188	2031
Aeroderivative Turbine (LM6000)	40	2,511	46.55	11.30	9,346	2025
Small Modular Nuclear Reactors	683	7,033	101.51	12.38	10,900	2040

Table 14. Renewable Resource Option Parameters

Technology	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr.)	Operating Life (Years)	First Year Available
Solar (PV)	1,554	23.82	30	2026
BESS (4-Hour)	1,860	46.49	20	2026
BESS (8-Hour)	3,355	83.88	20	2026
On-shore Wind	1,951	48.34	30	2029
Off-shore Wind	3,556	119.46	30	2040

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.





Santee Cooper

Integrated Resource Plan

2024 Update



Table 13. Fossil-Fueled and Nuclear Resource Option Parameters

Technology	Net Capacity (MW; Avg. Ambient)	Base Year Capital Costs (\$/kW)	Fixed O&M Cost (\$/kW-yr.)	Variable O&M Cost (\$/MWh)	Full Load Heat Rate (Btu/kWh)	Year First Available
Combined Cycle (2x1; H-class)	1,264	1,335	5.16	2.85	6,116	2031
Combined Cycle (Half of a 2x1; H-class; i.e., Shared Resource)	632	1,335	5.16	2.85	6,116	2031
Combined Cycle (1x1; H-class)	630	1,700	7.77	2.85	6,136	2031
Combined Cycle (1x1; F-class)	357	2,626	11.75	3.30	6,668	2031
Combustion Turbine (H-class)	402	1,674	5.10	9.80	9,386	2031
Combustion Turbine (F-class)	230	1,848	8.18	8.97	10,188	2031
Aeroderivative Turbine (LM6000)	40	2,511	46.55	11.30	9,346	2028
Small Modular Nuclear Reactors	683	7,033	101.51	12.38	10,900	2040

Capital costs are assumed to decline in real dollars by approximately 0.9 percent per year, based on projections taken from NREL's 2023 ATB for these assets. Hence, in nominal dollars, given the underlying general inflation assumption utilized in the 2024 IRP Update, capital costs are assumed to increase at approximately 1.4 percent per year. Fixed and variable O&M are assumed to escalate at the rate of general inflation, or 2.3 percent per year.

RENEWABLE AND ENERGY STORAGE RESOURCES

Utility-scale solar, wind (both onshore and offshore), and BESS resources have been reflected in EnCompass as PPA options based on estimates of the levelized cost of energy ("LCOE"), or in the case of BESS resources, levelized cost of capacity ("LCOC"), over their useful lives. Santee Cooper assumes, for purposes of the 2024 IRP Update, that renewable and BESS resources will be implemented through PPAs. However, Santee Cooper and Central will determine the implementation method that best meets their needs over time.

The 2024 IRP Update reflects the same annual planning limits on solar and onshore wind resource installations as assumed for the 2023 IRP. It should be noted that these limits are imposed for planning purposes, and Santee Cooper may work to acquire more or less renewable resources in any year. We will continue to evaluate the annual limits on solar and wind resources and will update the assumptions if warranted. The experience of the Stakeholder Working Group members and the results of procurement efforts, including the 2024 Solar RFP, will be helpful in considering these planning limits, and changes will be discussed with stakeholders as part of future IRP filings.

Capital and operating cost assumptions for solar, wind, and BESS resources have been taken from the NREL 2023 ATB. Capital costs for solar resources have been adjusted based on NREL's 2023Q1 Solar and Storage Cost Benchmark, which reflected approximately 10 percent higher

Major Modeling Assumptions

costs for these resources relative to the values reflected in the 2023 ATB.²⁰ Capital and operating costs for wind resources have been adjusted to reflect higher costs for Southeast projects relative to those in more prevalent wind resource regions based on data from EPRI and, for onshore wind resources, to reflect potentially higher costs for development of such resources in South Carolina (as there are no existing or proposed large-scale projects in the state).

The resulting capital and operating costs (in 2024 dollars and reflecting 2024 online dates) assumed for the 2024 IRP Update are provided in Table 14 below.²¹

Table 14. Renewable Resource Option Parameters

Technology	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr.)	Operating Life (Years)	First Year Available
Solar (PV)	1,554	23.82	30	2026
BESS (4-Hour)	1,860	46.49	20	2026
BESS (8-Hour)	3,355	83.88	20	2026
On-shore Wind	1,951	48.34	30	2029
Off-shore Wind	3,556	119.46	30	2040

New solar and BESS resources are assumed to be available beginning January 2026, while on-shore wind resources are assumed to be available beginning January 2029. Due to the development and permitting timeframe of off-shore wind resources, such resources are assumed to be available beginning 2040.

Financing costs are based on the 2023 ATB, reflecting the cost structure of a taxable developer, with some adjustments to assumed after-tax return on equity, to maintain consistency with broader interest rate trends, and financing structure. Table 15 below provides the debt interest rates and approximate after-tax return on equity values that underpin renewable and BESS PPA pricing.

²⁰ Available at <https://www.nrel.gov/docs/fy22osti/83586.pdf>. This publication has typically been a key source of base year values in the following year's ATB, which is the case for the 2024 ATB. As discussed previously, the 2024 IRP Update relies on the 2023 ATB, as most assumptions drawn from the ATB are very similar between the two releases, and Santee Cooper does not believe that conclusions presented herein would be impacted in a noticeable way by updating assumptions for the 2024 ATB.

²¹ As these technologies typically reflect declining real capital cost curves for future installations, the capital cost values for future install years will vary from these values.

DUKE 2023 CAROLINAS RESOURCE PLAN*

Table E-2: 2023 Generic Unit Overnight Technology Capital Costs

Technology	Technology Class	Cost (2023 \$/kW)	Notes
2x1 Combined Cycle	Baseload	\$800-1,250/kW	Includes duct firing kW, high firm transport O&M adder, low near-term cost decline
Generic Small Modular Reactor	Baseload	\$6,450/kW	Unavailable until mid-2030s, low near-term cost decline
Generic Advanced Reactor with Thermal Storage	Baseload	\$6,850/kW	Unavailable until late-2030s, moderate near-term cost decline
Multi-Unit Combustion Turbine	Intermediate/Peaking	\$750-\$900/kW	Multi-unit pricing, moderate firm transport O&M adder, low near-term cost decline
Solar PV SAT	Variable	\$1,850/kW	Moderate near-term cost decline
Onshore Wind	Variable	\$2,150/kW	Moderate near-term cost decline
Solar PV SAT + 20 MW/4-Hour Li-Ion Storage	Variable	\$2,550/kW	High near-term cost decline
Solar PV SAT + 40 MW/4-Hour Li-Ion Storage	Variable	\$3,200/kW	High near-term cost decline
Solar PV SAT + 60 MW/4-Hour Li-Ion Storage	Variable	\$3,850/kW	High near-term cost decline
Offshore Wind	Variable	\$4,150-\$4,850/kW	Unavailable until early 2030s, moderate near-term cost decline
4-Hour Li-Ion Storage	Storage	\$2,250/kW	High near-term cost decline
6-Hour Li-Ion Storage	Storage	\$3,300/kW	High near-term cost decline
8-Hour Li-Ion Storage	Storage	\$4,200/kW	High near-term cost decline

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

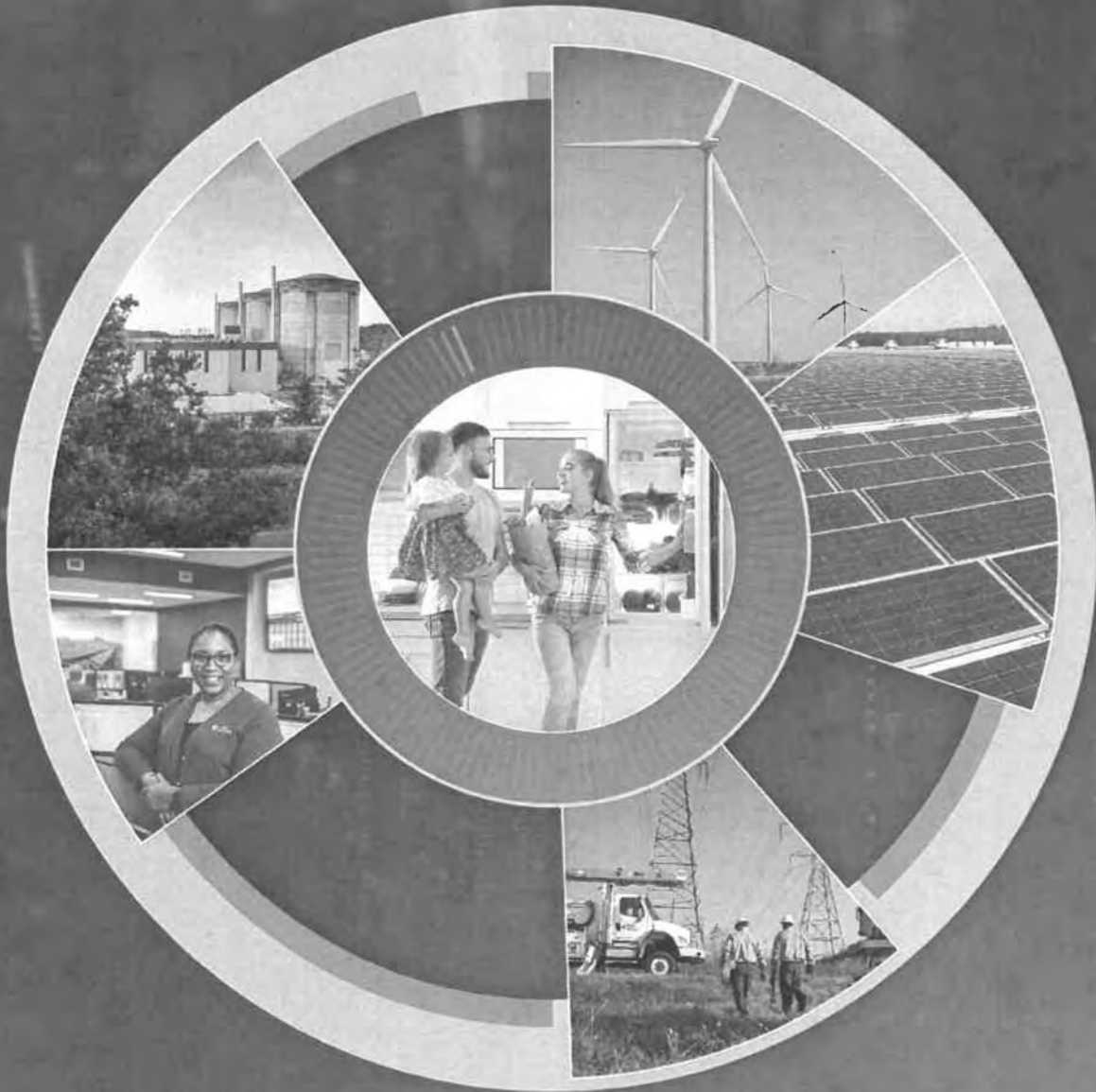


Table E-1: 2023 EIA AEO Technology Forecast Table

Year	Simple Cycle	Onshore Wind	Offshore Wind	Solar PV	Solar PV - Tracking w/ Storage	Battery Storage	Fuel Cell	Modified Pumped Hydro	Small Modular Reactor	Combined Cycle	Combined Cycle with CCS
2023	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2024	0.921	0.928	0.923	0.890	0.880	0.838	0.898	0.928	0.925	0.925	0.922
2025	0.874	0.887	0.880	0.821	0.795	0.723	0.826	0.837	0.881	0.881	0.876
2026	0.850	0.868	0.874	0.770	0.753	0.662	0.798	0.868	0.859	0.859	0.852
2027	0.839	0.860	0.863	0.748	0.721	0.631	0.760	0.895	0.849	0.848	0.839
2028	0.827	0.835	0.850	0.720	0.696	0.611	0.764	0.831	0.841	0.841	0.830
2029	0.815	0.850	0.848	0.702	0.677	0.590	0.749	0.828	0.833	0.832	0.819
2030	0.804	0.844	0.858	0.680	0.653	0.566	0.733	0.821	0.825	0.824	0.809
2031	0.793	0.838	0.846	0.661	0.633	0.544	0.717	0.815	0.816	0.816	0.798
2032	0.786	0.833	0.812	0.673	0.649	0.541	0.702	0.810	0.808	0.810	0.789
2033	0.780	0.829	0.802	0.665	0.637	0.537	0.688	0.806	0.801	0.805	0.781
2034	0.774	0.823	0.798	0.658	0.629	0.528	0.672	0.801	0.793	0.799	0.772
2035	0.767	0.816	0.787	0.648	0.620	0.518	0.657	0.795	0.785	0.793	0.763
2036	0.760	0.812	0.784	0.639	0.611	0.509	0.641	0.789	0.776	0.786	0.753
2037	0.753	0.806	0.774	0.631	0.603	0.500	0.626	0.784	0.768	0.780	0.744
2038	0.746	0.800	0.767	0.623	0.594	0.491	0.611	0.778	0.760	0.774	0.735
2039	0.739	0.795	0.760	0.614	0.586	0.482	0.596	0.773	0.752	0.767	0.728
2040	0.733	0.789	0.753	0.606	0.577	0.474	0.581	0.768	0.744	0.761	0.717
2041	0.726	0.784	0.746	0.598	0.568	0.465	0.566	0.762	0.736	0.755	0.709
2042	0.719	0.778	0.739	0.590	0.560	0.458	0.551	0.757	0.727	0.749	0.699
2043	0.712	0.772	0.732	0.581	0.552	0.447	0.536	0.751	0.719	0.742	0.690
2044	0.704	0.765	0.724	0.573	0.543	0.438	0.521	0.744	0.710	0.735	0.683
2045	0.697	0.759	0.717	0.564	0.534	0.428	0.506	0.738	0.701	0.728	0.670
2046	0.689	0.753	0.710	0.556	0.525	0.419	0.491	0.732	0.692	0.721	0.661
2047	0.682	0.746	0.702	0.547	0.517	0.410	0.478	0.726	0.684	0.714	0.652
2048	0.674	0.740	0.695	0.538	0.508	0.401	0.461	0.718	0.675	0.707	0.642
2049	0.667	0.733	0.688	0.530	0.499	0.392	0.446	0.713	0.666	0.700	0.633
2050	0.660	0.727	0.681	0.521	0.490	0.384	0.432	0.707	0.658	0.694	0.624



2023 Carolinas Resource Plan



BUILDING A SMARTER ENERGY FUTURE®

Table E-2: 2023 Generic Unit Overnight Technology Capital Costs

Technology	Technology Class	Cost (2023 \$/kW)	Notes
2x1 Combined Cycle	Baseload	\$800-1,250/kW	Includes duct firing kW, high firm transport O&M adder, low near-term cost decline
Generic Small Modular Reactor	Baseload	\$6,450/kW	Unavailable until mid-2030s, low near-term cost decline
Generic Advanced Reactor with Thermal Storage	Baseload	\$6,850/kW	Unavailable until late-2030s, moderate near-term cost incline
Multi-Unit Combustion Turbine	Intermediate/Peaking	\$750-\$900/kW	Multi-unit pricing, moderate firm transport O&M adder, low near-term cost decline
Solar PV SAT	Variable	\$1,850/kW	Moderate near-term cost decline
Onshore Wind	Variable	\$2,150/kW	Moderate near-term cost decline
Solar PV SAT + 20 MW/4-Hour Li-Ion Storage	Variable	\$2,550/kW	High near-term cost decline
Solar PV SAT + 40 MW/4-Hour Li-Ion Storage	Variable	\$3,200/kW	High near-term cost decline
Solar PV SAT + 60 MW/4-Hour Li-Ion Storage	Variable	\$3,850/kW	High near-term cost decline
Offshore Wind	Variable	\$4,150-\$4,850/kW	Unavailable until early 2030s, moderate near-term cost decline
4-Hour Li-Ion Storage	Storage	\$2,250/kW	High near-term cost decline
6-Hour Li-Ion Storage	Storage	\$3,300/kW	High near-term cost decline
8-Hour Li-Ion Storage	Storage	\$4,200/kW	High near-term cost decline

Table E-1: 2023 EIA AEO Technology Forecast Table

Year	Simple Cycle	Onshore Wind	Offshore Wind	Solar PV	Solar PV - Tracking w/ Storage	Battery Storage	Fuel Cell	Modified Pumped Hydro	Small Modular Reactor	Combined Cycle	Combined Cycle with CCS
2023	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2024	0.921	0.928	0.923	0.892	0.880	0.838	0.898	0.928	0.925	0.925	0.922
2025	0.874	0.887	0.866	0.821	0.799	0.723	0.826	0.887	0.881	0.881	0.876
2026	0.850	0.868	0.674	0.778	0.752	0.662	0.798	0.868	0.859	0.859	0.852
2027	0.836	0.860	0.663	0.746	0.721	0.631	0.780	0.849	0.849	0.848	0.839
2028	0.827	0.855	0.656	0.720	0.696	0.611	0.764	0.831	0.841	0.841	0.830
2029	0.815	0.850	0.648	0.702	0.677	0.590	0.749	0.826	0.833	0.832	0.819
2030	0.804	0.844	0.554	0.690	0.663	0.568	0.733	0.821	0.825	0.824	0.809
2031	0.793	0.838	0.546	0.681	0.653	0.554	0.717	0.815	0.816	0.816	0.798
2032	0.786	0.833	0.512	0.673	0.645	0.545	0.702	0.810	0.808	0.810	0.789
2033	0.780	0.829	0.505	0.665	0.637	0.537	0.688	0.806	0.801	0.805	0.781
2034	0.774	0.823	0.498	0.656	0.628	0.528	0.672	0.801	0.793	0.799	0.772
2035	0.767	0.818	0.491	0.648	0.620	0.519	0.657	0.795	0.785	0.793	0.763
2036	0.760	0.812	0.484	0.639	0.611	0.509	0.641	0.789	0.776	0.786	0.753
2037	0.753	0.806	0.474	0.631	0.602	0.500	0.626	0.784	0.768	0.780	0.744
2038	0.746	0.800	0.467	0.623	0.594	0.491	0.611	0.778	0.760	0.774	0.735
2039	0.739	0.795	0.460	0.614	0.585	0.482	0.596	0.773	0.752	0.767	0.726
2040	0.733	0.789	0.453	0.606	0.577	0.474	0.581	0.768	0.744	0.761	0.717
2041	0.726	0.784	0.446	0.598	0.569	0.465	0.566	0.762	0.736	0.755	0.709
2042	0.719	0.778	0.439	0.590	0.560	0.456	0.551	0.757	0.727	0.749	0.699
2043	0.712	0.772	0.432	0.581	0.552	0.447	0.536	0.751	0.719	0.742	0.690
2044	0.704	0.765	0.424	0.573	0.543	0.438	0.521	0.744	0.710	0.735	0.680
2045	0.697	0.759	0.417	0.564	0.534	0.428	0.506	0.738	0.701	0.728	0.670
2046	0.689	0.752	0.410	0.555	0.525	0.419	0.491	0.732	0.692	0.721	0.661
2047	0.682	0.746	0.402	0.547	0.517	0.410	0.476	0.726	0.684	0.714	0.652
2048	0.674	0.740	0.395	0.538	0.508	0.401	0.461	0.719	0.675	0.707	0.642
2049	0.667	0.733	0.388	0.530	0.499	0.392	0.446	0.713	0.666	0.700	0.633
2050	0.660	0.727	0.381	0.521	0.491	0.384	0.432	0.707	0.658	0.694	0.624

INDIANA MICHIGAN POWER 2024 INDIANA IRP*

Table 18 below shows first year operating and maintenance costs and heat rates modeled for new NGCC.

Table 18. First Year New NGCC Operating Cost and Heat Rate Assumptions

		H-Class Multi-Shaft (1,630 MW)	H-Class Single Shaft (420 MW)
Variable Operations & Maintenance (VOM)	\$ / MWh	2.53	3.45
Fixed Operations & Maintenance (FOM)	\$ / kW-yr	16.51	19.09
Heat Rate	Btu / kWh	6,370	6,430

Table 19. First Year Existing NGCC Resource and Operating Costs and Heat Rate Assumptions

		Existing NGCC (5 Year) (900 MW)	Existing NGCC (10 Year) (900 MW)	Existing NGCC (20 Year) (900 MW)
Installed Cost	\$/MW-D or \$/kW	680 \$/MW-D	680 \$/MW-D	1,100 \$/kW
VOM	\$ / MWh	3.502	3.502	3.502
FOM	\$ / kW-yr	176.96224	176.96224	16.6121.02
Heat Rate	Btu / kWh	6,989.4	6,989.4	6,989.4

The first operating year SMR operating costs and heat rate assumptions are shown in Table 20 below.

Table 20. SMR Operating Costs and Heat Rate Assumptions

		SMR (600 MW)
VOM	\$ / MWh	4.55
FOM	\$ / kW-yr	143.79
Heat Rate	Btu / kWh	10,447

Table 21 shows first year operating and maintenance costs and heat rates modeled for new NGCC with CCS.

Table 21. NGCC w/ CCS Operating Cost and Heat Rate Assumptions

		NGCC w/ CCS (380 MW)
VOM	\$ / MWh	8.50
FOM	\$ / kW-yr	40.18
Heat Rate	Btu / kWh	7,120

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

EXHIBIT

GIPLSF-6F

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Table 22 shows first year operating and maintenance costs and heat rates modeled for new NGCT.

Table 22 NGCT Operating Cost and Heat Rate Assumptions

F-Class NGCT (240MW)		
VOM	\$ / MWh	5.98
FOM	\$ / kW-yr	9.31
Heat Rate	Btu / kWh	9,910

Table 23 First Year Existing NGCT Resource and Operating Costs and Heat Rate Assumptions

		Existing NGCT (5 Year) (600 MW)	Existing NGCT (10 Year) (500 MW)	Existing NGCT (20 Year) (500 MW)
Installed Cost	\$/MW-D or \$/kW	493 \$/MW-D	493 \$/MW-D	844 \$/kW
VOM	\$ / MWh	1.33	1.33	1.33
FOM	\$ / kW-yr	147.85	147.85	22.25
Heat Rate	Btu / kWh	10,888	10,888	10,888

Table 24 shows first year operating and maintenance costs and heat rates used for aeroderivative turbines.

Table 24. Aeroderivative Turbine Operating Cost and Heat Rate Assumptions

AD (110 MW)		
VOM	\$ / MWh	6.36
FOM	\$ / kW-yr	22.07
Heat Rate	Btu / kWh	9,120

Table 25 shows first year operating costs and heat assumptions modeled for RICE resources.

Table 25. RICE Operating Cost and Heat Rate Assumptions

RE (20 MW)		
VOM	\$ / MWh	7.70
FOM	\$ / kW-yr	47.59
Heat Rate	Btu / kWh	8,300

Table 26 shows the first operating year fixed operations and maintenance cost (FOM).

Table 26. Solar First Year Fixed Operating Costs

Solar (150 MW)		
FOM	\$ / kW-yr	9.59

Table 27 shows the first operating year fixed operations and maintenance cost (FOM).

Table 27 Wind First Year Fixed Operating Costs

Wind (200 MW)		
FOM	\$ / kW-yr	21.97

Table 29 shows the first operating year fixed operations and maintenance cost (FOM), and heat rate assumptions.

Table 29 Battery Storage First Year Fixed Operating Cost

		Storage 4-Hr (50 MW)	Storage 6-Hr (50 MW)	Storage 8-Hr (50 MW)	Storage 100-hr (20 MW)
FOM	\$ / kW-yr	52.14	79.66	106.21	18.99

Table 30 shows the first operating year fixed operations and maintenance cost (FOM).

Table 30 Solar plus Storage First Year Fixed Operating Costs

Solar (160MW)		
FOM	\$ / kW-yr	35.36



INDIANA INTEGRATED RESOURCE PLANNING REPORT

to the:
Indiana Utility Regulatory Commission

Submitted Pursuant to:
Commission Rule 170 IAC 4-7

March 28, 2025

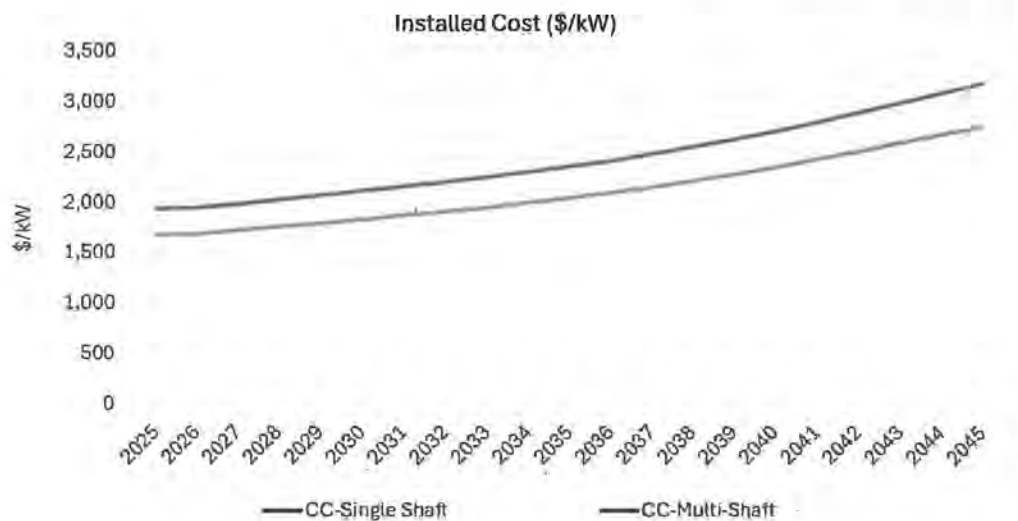


Figure 27. NGCC – Single and Multi-Shaft Installed Costs

Table 18 below shows first year operating and maintenance costs and heat rates modeled for new NGCC.

Table 18. First Year New NGCC Operating Cost and Heat Rate Assumptions

		H-Class Multi-Shaft (1,030 MW)	H-Class Single Shaft (420 MW)
Variable Operations & Maintenance (VOM)	\$ / MWh	2.53	3.45
Fixed Operations & Maintenance (FOM)	\$ / kW-yr	16.51	19.09
Heat Rate	Btu / kWh	6,370	6,430

In addition to new NGCC resources, three existing NGCC resources were modeled. The first two existing NGCC resources were modeled as proxy power purchase resources with five- and ten-year contract periods. The third existing NGCC resource was modeled based upon acquisition and ownership of an existing resource, assuming 20 years remaining life. These three existing NGCC resources were all made available in the model with a first operating year of 2028, reflective of the anticipated period required for regulatory approvals. The installed cost for existing NGCC resources was developed with market-based intelligence and was confirmed by the Company's 2024 RFPs. Table 19 below shows the installed cost assumptions used for the existing NGCC resources.

Table 19. First Year Existing NGCC Resource and Operating Costs and Heat Rate Assumptions

		Existing NGCC	Existing NGCC	Existing NGCC
		(5 Year)	(10 Year)	(20 Year)
		(900 MW)	(900 MW)	(900 MW)
Installed Cost	\$/MW-D or \$/kW	680 \$/MW-D	680 \$/MW-D	1,100 \$/kW
VOM	\$ / MWh	3.502	3.502	3.502
FOM	\$ / kW-yr	176.96224	176.96224	16.6121.02
Heat Rate	Btu / kWh	6,989.4	6,989.4	6,989.4

It's important to note that the NGCC technology discussed above can in fact operate on several different fuels with modifications to the NGCC. In recent years, major NGCC manufacturers have refined the combustion characteristics of their respective offerings to effectively combust a wide array of industrial and synthetic fuels – including hydrogen. So called “green” hydrogen¹⁶ produced from electrolysis of water using renewable power has seen increased development over the past few years. Depending upon the exact model, many NGCCs are currently capable of firing hydrogen/natural gas fuel blends ranging up to approximately 30% hydrogen. The major manufacturers continue research and development of new combustion hardware with goals of reaching 100% hydrogen firing in the next several years. Although, the availability and adequacy of “green” hydrogen supply to NGCC facilities must be considered.

8.1.2.2 Cook Relicense

The Cook Nuclear plant is an existing generation resource that I&M owns and operates and provides significant contributions to both capacity and energy requirements for Indiana customers. Currently, the licenses of Cook Units 1 and 2 will expire in Q4 2034 and Q4 2037, respectively. The 2024 IN IRP resource options included a 20-year Subsequent License Renewal (SLR or relicensing) of each unit. For each scenario and sensitivity, the modeling optimized the decision whether to retire or relicense both Cook units, considering economic and reliability impacts.

Costs considered in the relicensing of Cook were based on the best information available at the time IRP inputs were developed. These costs are subject to change in the future as the SLR process proceeds and additional information is obtained. The SLR cost estimates used in the IRP include a \$42.5M SLR cost that was based on benchmarking with other nuclear utilities undergoing the same effort. Another component of future costs supporting the SLR is the one-time inspections that will be required after receiving the new license but prior to the subsequent period of extended operation. An estimate of \$20M was used based on the experience of a contracted engineering firm. After the

¹⁶Green hydrogen is made with electrolyzers powered by non-carbon emitting resources. Other types of hydrogen production, for example “blue” hydrogen, are made from reforming methane with CCS of the CO₂ byproduct.

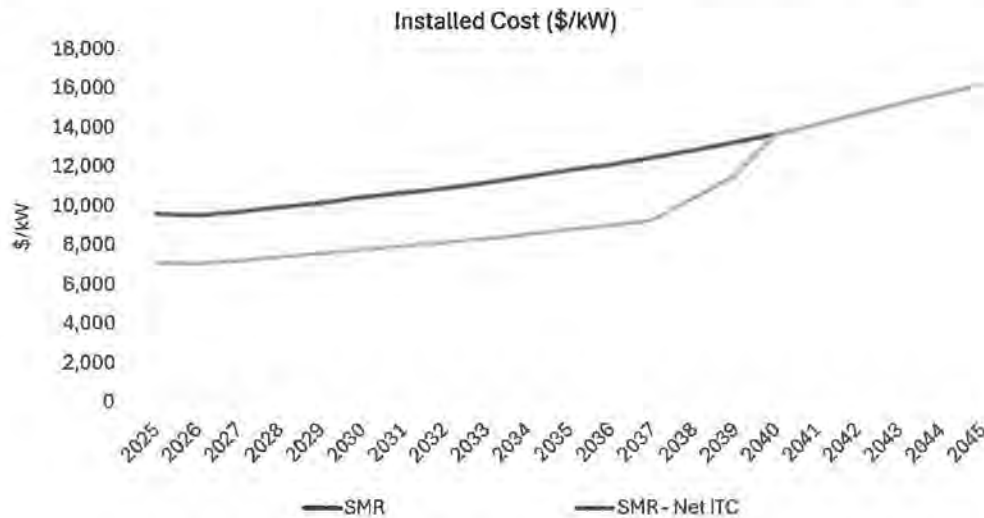


Figure 28. SMR Installed Costs

The first operating year SMR operating costs and heat rate assumptions are shown in Table 20 below.

Table 20. SMR Operating Costs and Heat Rate Assumptions

SMR (600 MW)		
VOM	\$ / MWh	4.55
FOM	\$ / kW-yr	143.79
Heat Rate	Btu / kWh	10,447

8.1.2.4 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) technology provides another alternative for producing reliable low-carbon baseload electricity. CO₂ in the flue gas from the combustion of fossil fuels is captured by amine-based solvent in the absorption column and then released from the solvent in a concentrated form in a stripper column. The process requires a significant amount of steam to break the bond between the CO₂ and the solvent, and auxiliary power to run the CO₂ compressor and other mechanical equipment. As such, CCS-equipped power plants have significant heat rate and capacity penalties relative to power plants without CCS.

NGCCs with CCS are modeled in PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One new build NGCC with CCS configuration is available for selection in PLEXOS®, as a 380 MW H-class single shaft, NGCC with 90% CCS. This resource is made available in the model with the first

operating year of 2035, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

The assumption on installed costs for the new build NGCC with CCS is shown in Figure 29.

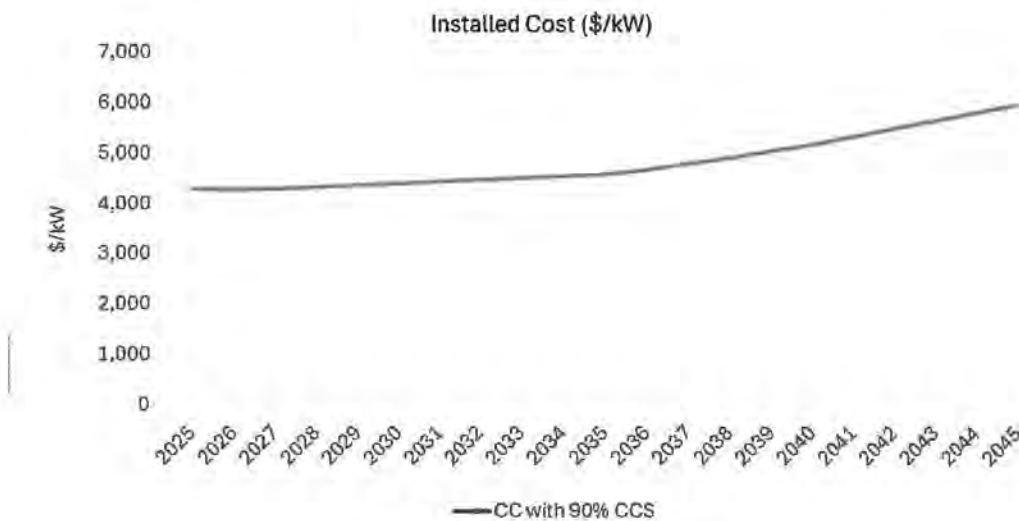


Figure 29. NGCC with CCS Installed Costs

Table 21 shows first year operating and maintenance costs and heat rates modeled for new NGCC with CCS.

Table 21. NGCC w/ CCS Operating Cost and Heat Rate Assumptions

		NGCC w/ CCS (380 MW)
VOM	\$ / MWh	8.50
FOM	\$ / kW-yr	40.18
Heat Rate	Btu / kWh	7,120

8.1.3 Peaking Alternatives

Peaking sources have traditionally provided additional generating capacity during demand peaks that typically occur a few hundred hours each year but can occur more or less. Given the low utilization of peaking generators, focus in the past has been on minimizing capital and fixed costs instead of fuel efficiency and other variable costs.

More recently, greater amounts of intermittent renewable generation in the market combined with more extreme weather patterns have necessitated more flexible resources. For example, an unanticipated drop in wind generation during the day will require quick response from other

Table 22 shows first year operating and maintenance costs and heat rates modeled for new NGCT.

Table 22. NGCT Operating Cost and Heat Rate Assumptions

		F-Class NGCT (240MW)
VOM	\$ / MWh	5.98
FOM	\$ / kW-yr	9.31
Heat Rate	Btu / kWh	9,910

In addition to new NGCT resources, three existing NGCT resources were modeled. The first two existing NGCT resources were modeled as proxy power purchase resources with five- and ten-year contract periods. The third existing NGCT resource was modeled based upon acquisition and ownership of an existing resource, assuming 20 years remaining life. These three existing NGCT resources were all made available in the model with a first operating year of 2028, reflective of the anticipated period required for regulatory approvals. The installed costs for existing NGCT resources were developed with market-based intelligence and were confirmed by the 2024 RFPs. Table 23 below shows the installed cost assumptions used for the existing NGCT resources.

Table 23. First Year Existing NGCT Resource and Operating Costs and Heat Rate Assumptions

		Existing NGCT (5 Year) (500 MW)	Existing NGCT (10 Year) (500 MW)	Existing NGCT (20 Year) (500 MW)
Installed Cost	\$/MW-D or \$/kW	493 \$/MW-D	493 \$/MW-D	644 \$/kW
VOM	\$ / MWh	1.33	1.33	1.33
FOM	\$ / kW-yr	147.85	147.85	22.25
Heat Rate	Btu / kWh	10,888	10,888	10,888

8.1.3.2 Aeroderivative Turbines

Aeroderivative turbine (AD) units are based off aircraft jet engines designs and are modified for use in power generation. Their operating characteristics make them well suited with high renewable penetration as they can quickly respond to significant shifts in supply and demand conditions in the power system. For example, the GE 9E series NGCT requires 30 minutes to start up whereas the GE LM6000 AD unit requires only 5 minutes. This allows AD units to operate at full load even for a small amount of time. In addition, AD units are more efficient in a simple cycle operation than NGCTs for capacity less than 100 MW. However, AD units are relatively more expensive than NGCTs.

AD units are modeled in PLEXOS® in 110 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

Figure 31 below shows the installed cost assumptions used for the new AD resource.

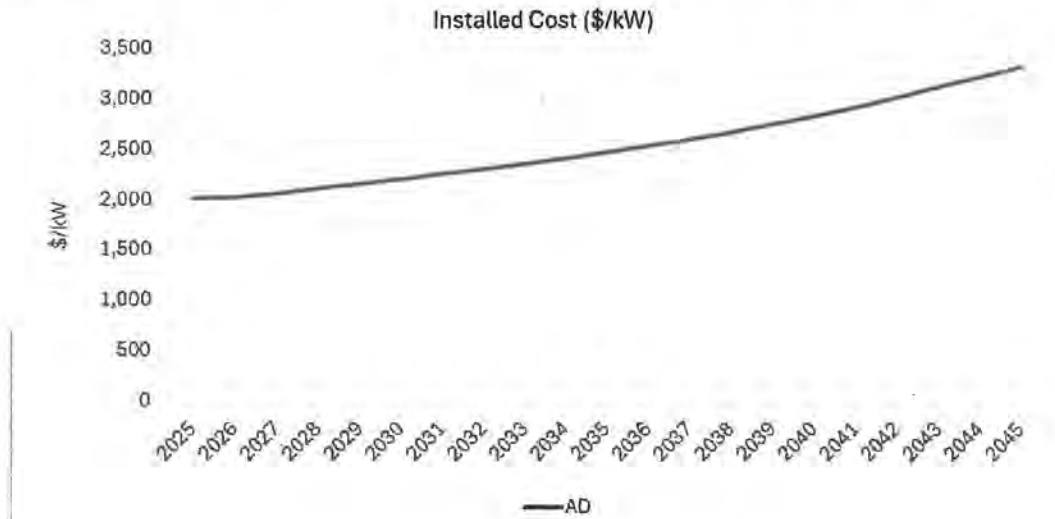


Figure 31. Aeroderivative Turbine Installed Costs

Table 24 shows first year operating and maintenance costs and heat rates used for aeroderivative turbines.

Table 24. Aeroderivative Turbine Operating Cost and Heat Rate Assumptions

		AD (110 MW)
VOM	\$ / MWh	6.36
FOM	\$ / kW-yr	22.07
Heat Rate	Btu / kWh	9,120

8.1.3.3 Reciprocating Internal Combustion Engine

Like NGCTs, Reciprocating Internal Combustion Engines (RICE) rely on the combustion of air mixed with fuel to generate hot pressurized gases. Unlike NGCTs, the expansion of these gases creates pressure within piston chambers which is used to drive a rotating motion to generate electricity. Multiple RICE units are usually incorporated into a larger generating set for main grid applications.

RICE generating sets can usually start and reach full load in less than five minutes, making them even faster than AD units in responding to system needs. RICE generating sets can also run more efficiently at partial load as individual RICE units within the generating set can be shut down to

reduce output while allowing remaining units to run a full load. Unlike NGCTs or ADs, RICE units can be started multiple times in a day without incurring additional maintenance costs. These characteristics make RICE units well suited for power systems that require frequent but short-duration dispatches.

RICE units are modeled in PLEXOS® in 20 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for PJM interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction.

Figure 32 below shows the installed cost assumptions used for the new RICE resources.

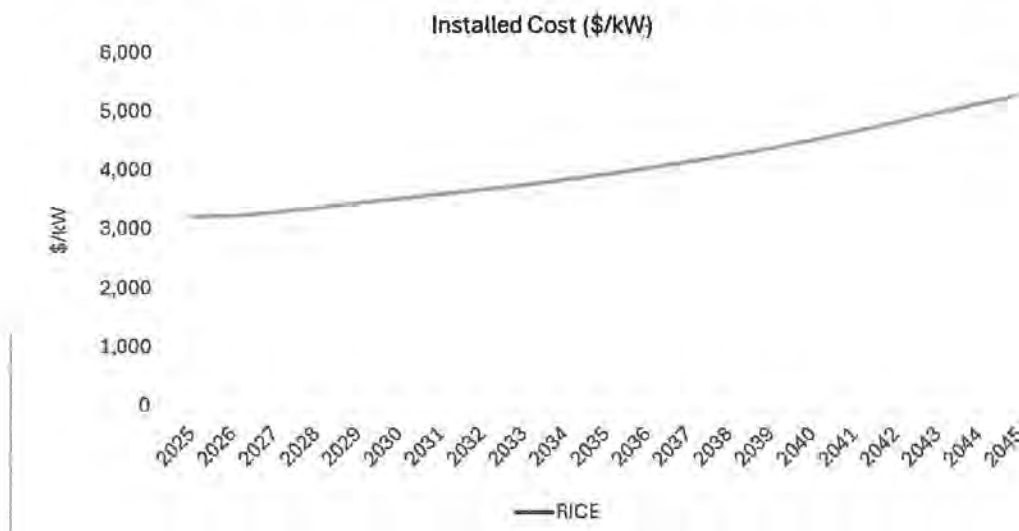


Figure 32. RICE Installed Costs

Table 25 shows first year operating costs and heat assumptions modeled for RICE resources.

Table 25. RICE Operating Cost and Heat Rate Assumptions

		RE (20 MW)
VOM	\$ / MWh	7.70
FOM	\$ / kW-yr	47.59
Heat Rate	Btu / kWh	8,300

8.1.4 Renewable Alternatives

Renewable generation alternatives such as wind, solar, and hydro, provide an opportunity to deliver affordable clean energy to address future electricity needs when cost effective. These technologies

Figure 33 below shows the installed cost assumptions used for the 35-year solar resource.

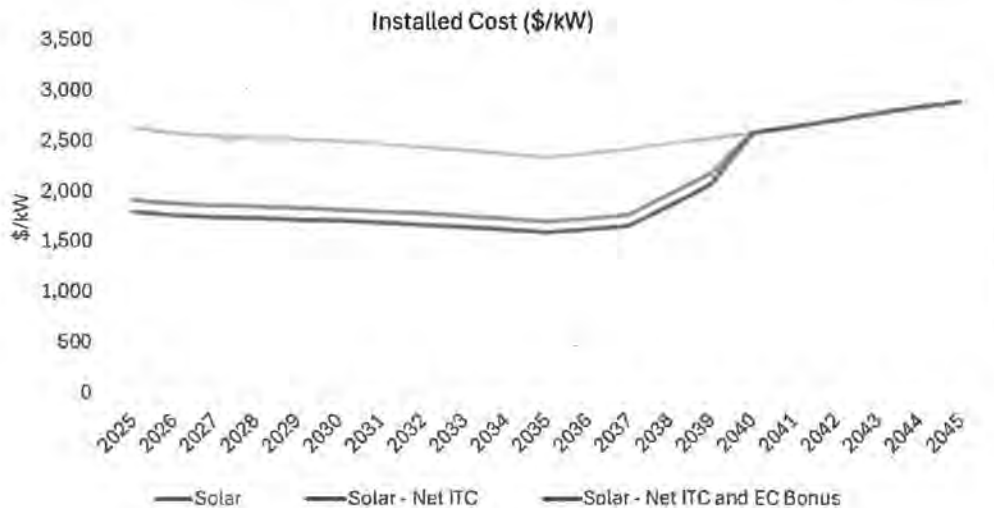


Figure 33. Solar Installed Costs

Table 26 shows the first operating year fixed operations and maintenance cost (FOM).

Table 26. Solar First Year Fixed Operating Costs

Solar (150 MW)		
FOM	\$ / kW-yr	9.59

8.1.4.2 Wind

Onshore wind (wind) energy is based on exploiting the air pressure differential across two sides of a rotor blade, causing the rotor blade to spin and generate electricity. Typically, multiple wind turbines are grouped to develop a wind turbine power project which requires only a single connection to the transmission system. Careful site selection and turbine placement within the project is critical as wind velocity varies by geography, and the proximity of the wind farm to a transmission system with available capacity can impact cost. The most critical factors (*i.e.*, wind speed and sustainability) are typically highest in remote locations, requiring the electricity generated from wind resources to be transmitted longer distances to load centers necessitating the build out of high voltage transmission to optimally integrate large additions of wind into the grid. This is considered through the higher network and interconnection costs for wind resources, noted in Section 8.1.1.5.

Wind units are modeled in PLEXOS® in 200 MW units as non-dispatchable renewable resources. Wind is first made available as a resource option in PLEXOS® in 2028, reflective of the anticipated

period required for regulatory approvals. They are modeled with a generic hourly production profile representative of the region with an average capacity factor of 33%.

Two types of wind resources were modeled. The first was modeled as proxy power purchase resource with a 15-year contract period and a cost of \$86/MWh. The second was modeled based upon resource ownership, assuming a 30-year life.

Figure 34 below shows the installed cost assumptions used for the 30-year wind resource.

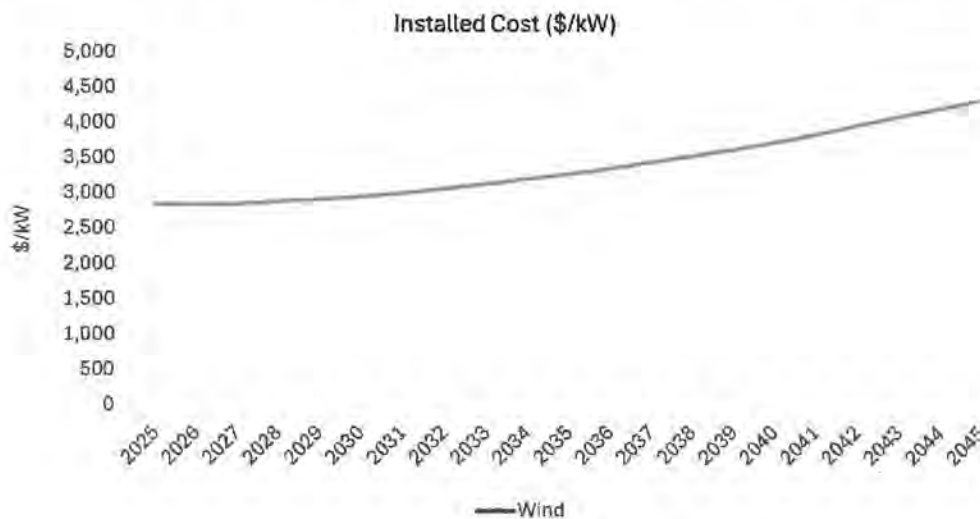


Figure 34. Wind Resources All-in Capital Expenditures

Table 27 shows the first operating year fixed operations and maintenance cost (FOM).

Table 27. Wind First Year Fixed Operating Costs

		Wind (200 MW)
FOM	\$ / kW-yr	21.97

8.1.4.3 Hydro Relicense

I&M owns six hydro facilities along the St. Joseph River in northern Indiana and southwest Michigan. Two of the hydro facilities have FERC license expiration dates within the next ten years: the Elkhart Hydroelectric Plant in 2030, and the Mottville Hydroelectric Plant in 2033.

As part of the overall relicensing evaluation, including I&M's IRP analysis, I&M engaged WSP USA, Inc, to conduct a four-phase study of the hydro facilities. The four phases consisted of: Phase 1 Decommissioning, Phase 2 Public Engagement, Phase 3 Socioeconomic Analysis, and Phase 4 Relicense. The scope began with a phased approach to evaluating an updated decommissioning

Figure 35 below shows the installed cost assumptions used for the battery resources.

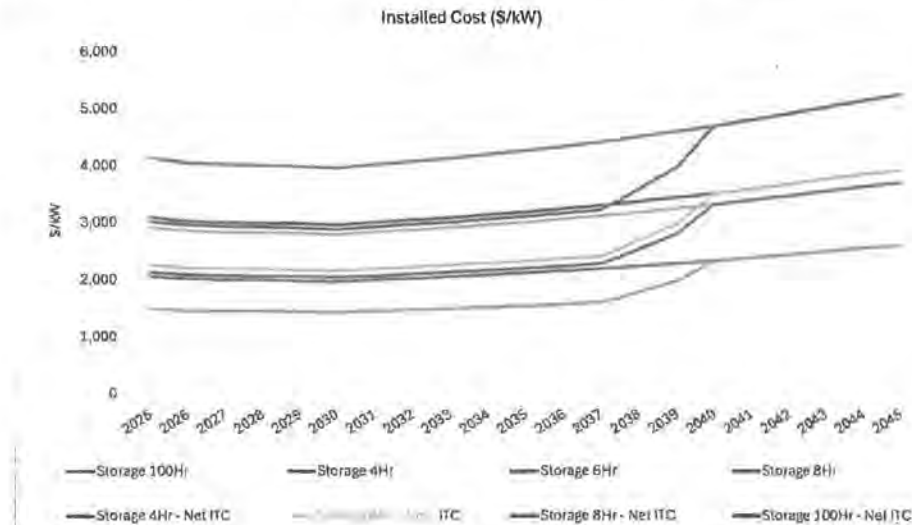


Figure 35. Battery Storage All-in Capital Expenditures

Table 29 shows the first operating year fixed operations and maintenance cost (FOM), and heat rate assumptions.

Table 29. Battery Storage First Year Fixed Operating Cost

		Storage 4-Hr (50 MW)	Storage 6-Hr (50 MW)	Storage 8-Hr (50 MW)	Storage 100-hr (20 MW)
FOM	\$ / kW-yr	52.14	79.66	106.21	18.99

See Section 8.1.5.3 below for a discussion of the co-located solar and storage resource included in the 2024 IN IRP.

8.1.5.2 Distribution Sited Storage

The 2024 IN IRP included seven distribution sited battery storage resource options for selection by the PLEXOS® model. The distribution storage resources are dispatched against fundamental market prices in an hourly chronological production cost model and then the generation and charge costs are extracted and placed as inputs into the expansion planning model. These were operated similar to the battery units described in the previous section.

These battery resources represent alternative solutions to traditional distribution projects to address either thermal or reliability issues. The thermal use case can address thermal overloads on distribution substation equipment during peak demand time periods. The reliability use case can address outage impacts to customers throughout the entire year.

8.1.5.3 Co-located Solar and Storage

For co-located solar and storage, PLEXOS® can choose to pair utility-scale photovoltaic with a lithium-ion battery where a paired solution is economic. The 2024 IN IRP included a co-located solar and battery option, available in 200 MW blocks (150MW solar plus 50MW of 4-hour duration battery storage). Figure 36 below shows the installed cost assumptions used for the solar with storage resource.

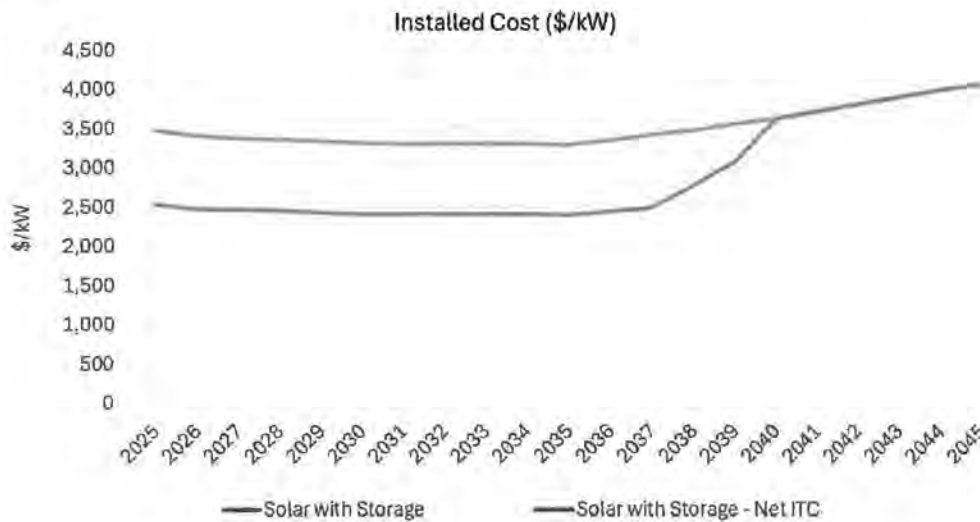


Figure 36. Solar with Storage Installed Costs

Table 30 shows the first operating year fixed operations and maintenance cost (FOM).

Table 30. Solar plus Storage First Year Fixed Operating Costs

Solar (150MW)		
FOM	\$ / kW-yr	35.36

8.2 New Demand-Side Resources

As part of the 2024 IN IRP, additional or "incremental" demand-side resources beyond those described in Section 6.5 were identified and modeled based on the 2024 MPS performed by GDS Associates and Brightline Group ("the GDS Team"). Non-income qualified EE, DR, and DER programs were modeled on a comparable economic basis as supply-side programs while income qualified demand-side programs were informed by the MPS and included in the 2024 IN IRP.

8.2.1 Demand-side Management Market Potential Study Overview

To evaluate the potential for future DSM resources in the 2024 IN IRP, I&M utilized the 2024 MPS prepared by the GDS Team for EE, DR, and DER potential. The 2024 MPS provided updated DSM

DOMINION VIRGINIA 2024 IRP*

Appendix 3K-2: Tabular Results of Busbar Capacity Factor (%)

3kW-Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
3x1 CC Greenfield	\$ 205	\$ 305	\$ 348	\$ 387	\$ 427	\$ 468	\$ 509	\$ 549	\$ 590	\$ 630	\$ 671
2x1 CC Greenfield	\$ 327	\$ 308	\$ 409	\$ 450	\$ 490	\$ 531	\$ 572	\$ 613	\$ 654	\$ 694	\$ 735
1x1 CC Greenfield	\$ 524	\$ 585	\$ 808	\$ 847	\$ 888	\$ 929	\$ 970	\$ 1,011	\$ 1,052	\$ 1,093	\$ 1,134
4X CT	\$ 189	\$ 237	\$ 308	\$ 374	\$ 443	\$ 512	\$ 580	\$ 649	\$ 717	\$ 786	\$ 854
2X Advanced CT	\$ 192	\$ 251	\$ 330	\$ 399	\$ 468	\$ 537	\$ 605	\$ 674	\$ 743	\$ 812	\$ 881
4X Aero CT	\$ 392	\$ 457	\$ 523	\$ 588	\$ 654	\$ 720	\$ 786	\$ 851	\$ 916	\$ 982	\$ 1,047
2X Aero CT	\$ 989	\$ 804	\$ 720	\$ 785	\$ 851	\$ 917	\$ 982	\$ 1,048	\$ 1,113	\$ 1,179	\$ 1,245
Nuclear SHR	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277
Solar - Tracker	\$ 284	\$ 223	\$ 182	\$ 141	\$ 100	\$ 59	\$ 17	\$ (24)	\$ (85)	\$ (146)	\$ (207)
Distributed Solar (3 MW)	\$ 520	\$ 404	\$ 288	\$ 172	\$ 46	\$ (390)	\$ (384)	\$ (378)	\$ (372)	\$ (366)	\$ (360)
Wind - On-Shore	\$ 345	\$ 303	\$ 261	\$ 219	\$ 178	\$ 134	\$ 82	\$ 30	\$ (7)	\$ (36)	\$ (77)
Wind - Off-Shore 1	\$ 957	\$ 515	\$ 472	\$ 429	\$ 387	\$ 344	\$ 302	\$ 259	\$ 216	\$ 174	\$ 131
Wind - Off-Shore 2	\$ 307	\$ 318	\$ 329	\$ 340	\$ 351	\$ 362	\$ 373	\$ 385	\$ 396	\$ 407	\$ 419
Battery Genesis 4H (30 MW)	\$ 522	\$ 533	\$ 544	\$ 555	\$ 566	\$ 577	\$ 588	\$ 599	\$ 611	\$ 622	\$ 633
Battery Genesis 8H (20 MW)	\$ 968	\$ 951	\$ 936	\$ 921	\$ 906	\$ 891	\$ 876	\$ 861	\$ 846	\$ 831	\$ 816

Notes:

- (1) Offshore Wind has a capacity factor of 42%.
- (2) Onshore Wind has a capacity factor of 37%.
- (3) Solar has a capacity factor of 25%.
- (4) Distributed solar has a capacity factor of 24%.
- (5) Batteries and Pump Storage have a capacity factor of 10%.

*Summary of selected screenshots, compiled by counsel for GIPL and Southface.

Appendix 3K-2: Tabular Results of Busbar

\$/kW-Year	Capacity Factor (%)										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
3x1 CC Greenfield	\$ 265	\$ 305	\$ 346	\$ 387	\$ 427	\$ 468	\$ 509	\$ 549	\$ 590	\$ 630	\$ 671
2x1 CC Greenfield	\$ 327	\$ 368	\$ 409	\$ 450	\$ 490	\$ 531	\$ 572	\$ 613	\$ 654	\$ 694	\$ 735
1x1 CC Greenfield	\$ 524	\$ 565	\$ 606	\$ 647	\$ 688	\$ 729	\$ 770	\$ 811	\$ 852	\$ 893	\$ 934
4X CT	\$ 169	\$ 237	\$ 306	\$ 374	\$ 443	\$ 512	\$ 580	\$ 649	\$ 717	\$ 786	\$ 854
2X Advanced CT	\$ 192	\$ 261	\$ 330	\$ 399	\$ 468	\$ 537	\$ 606	\$ 674	\$ 743	\$ 812	\$ 881
4X Aero CT	\$ 392	\$ 457	\$ 523	\$ 588	\$ 654	\$ 720	\$ 785	\$ 851	\$ 916	\$ 982	\$ 1,047
2X Aero CT	\$ 589	\$ 654	\$ 720	\$ 786	\$ 851	\$ 917	\$ 982	\$ 1,048	\$ 1,113	\$ 1,179	\$ 1,245
Nuclear SMR	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277	\$ 1,277
Solar - Tracker	\$ 264	\$ 223	\$ 182	\$ 141	\$ 100	\$ 59	\$ 17	\$ (24)	\$ (65)	\$ (106)	\$ (147)
Distributed Solar (3 MW)	\$ 520	\$ 494	\$ 468	\$ 442	\$ 416	\$ 390	\$ 364	\$ 338	\$ 312	\$ 286	\$ 260
Wind - On-Shore	\$ 345	\$ 303	\$ 261	\$ 219	\$ 176	\$ 134	\$ 92	\$ 50	\$ 7	\$ (35)	\$ (77)
Wind - Off-Shore 1	\$ 469	\$ 426	\$ 384	\$ 341	\$ 298	\$ 256	\$ 213	\$ 171	\$ 128	\$ 85	\$ 43
Wind - Off-Shore 2	\$ 557	\$ 515	\$ 472	\$ 429	\$ 387	\$ 344	\$ 302	\$ 259	\$ 216	\$ 174	\$ 131
Battery Generic 4H (30 MW)	\$ 307	\$ 318	\$ 329	\$ 340	\$ 351	\$ 362	\$ 374	\$ 385	\$ 396	\$ 407	\$ 418
Battery Generic 8H (30 MW)	\$ 522	\$ 533	\$ 544	\$ 555	\$ 566	\$ 577	\$ 588	\$ 599	\$ 611	\$ 622	\$ 633
Pump Hydro Storage (300 MW)	\$ 966	\$ 951	\$ 936	\$ 921	\$ 906	\$ 891	\$ 876	\$ 861	\$ 846	\$ 831	\$ 816

Notes:

- (1) Offshore Wind has a capacity factor of 42%.
- (2) Onshore Wind has a capacity factor of 37%.
- (3) Solar has a capacity factor of 25%.
- (4) Distributed solar has a capacity factor of 24%.
- (5) Batteries and Pump Storage have a capacity factor of 15%.

Appendix 3K-3: Busbar Assumptions

Nominal \$	Heat Rate	Variable Cost ⁽¹⁾	Fixed Cost ⁽²⁾		Book Life	2024 Real \$ ⁽³⁾
	MMBtu/MWh	\$/MWh	\$/kW-Year	\$/MWh	Years	\$/kW
3x1 CC Greenfield	6.14	\$46	\$265	\$76	36	\$1,523
2x1 CC Greenfield	6.13	\$47	\$327	\$93	36	\$1,667
1x1 CC Greenfield	6.12	\$47	\$524	\$149	36	\$2,000
4X CT	10.37	\$78	\$169	\$128	36	\$1,562
2X Advanced CT	10.37	\$79	\$192	\$146	20	\$1,781
4X Aero CT	9.91	\$75	\$392	\$298	36	\$3,977
2X Aero CT	9.91	\$75	\$589	\$448	36	\$5,479
Nuclear SMR	\$12	\$0	\$1,277	\$158	60	\$11,147
Solar - Tracker	-	-\$47	\$264	\$124	35	\$2,278
Distributed Solar (3 MW)	-	-\$30	\$520	\$243	30	\$4,675
Wind - On-Shore	-	-\$48	\$345	\$150	25	\$2,400
Wind - Off-Shore 1	-	-\$49	\$469	\$127	30	\$4,497
Wind - Off-Shore 2	-	-\$49	\$557	\$151	30	\$5,164
Battery Generic 4H (30 MW)	-	\$13	\$307	\$210	20	\$2,782
Battery Generic 8H (30 MW)	-	\$13	\$522	\$179	20	\$4,666
Pump Hydro Storage (300 MW)	-	-\$17	\$966	\$735	50	\$9,667

Notes:

(1) Variable costs for solar and wind includes RECs value.

(2) Fixed costs include capital expenditures, fixed O&M, federal tax credits, and gas firm transmission expenses.

(3) Values in this column represent overnight installed cost.

[C2]

**2022 – 2024
SYSTEM PERFORMANCE**



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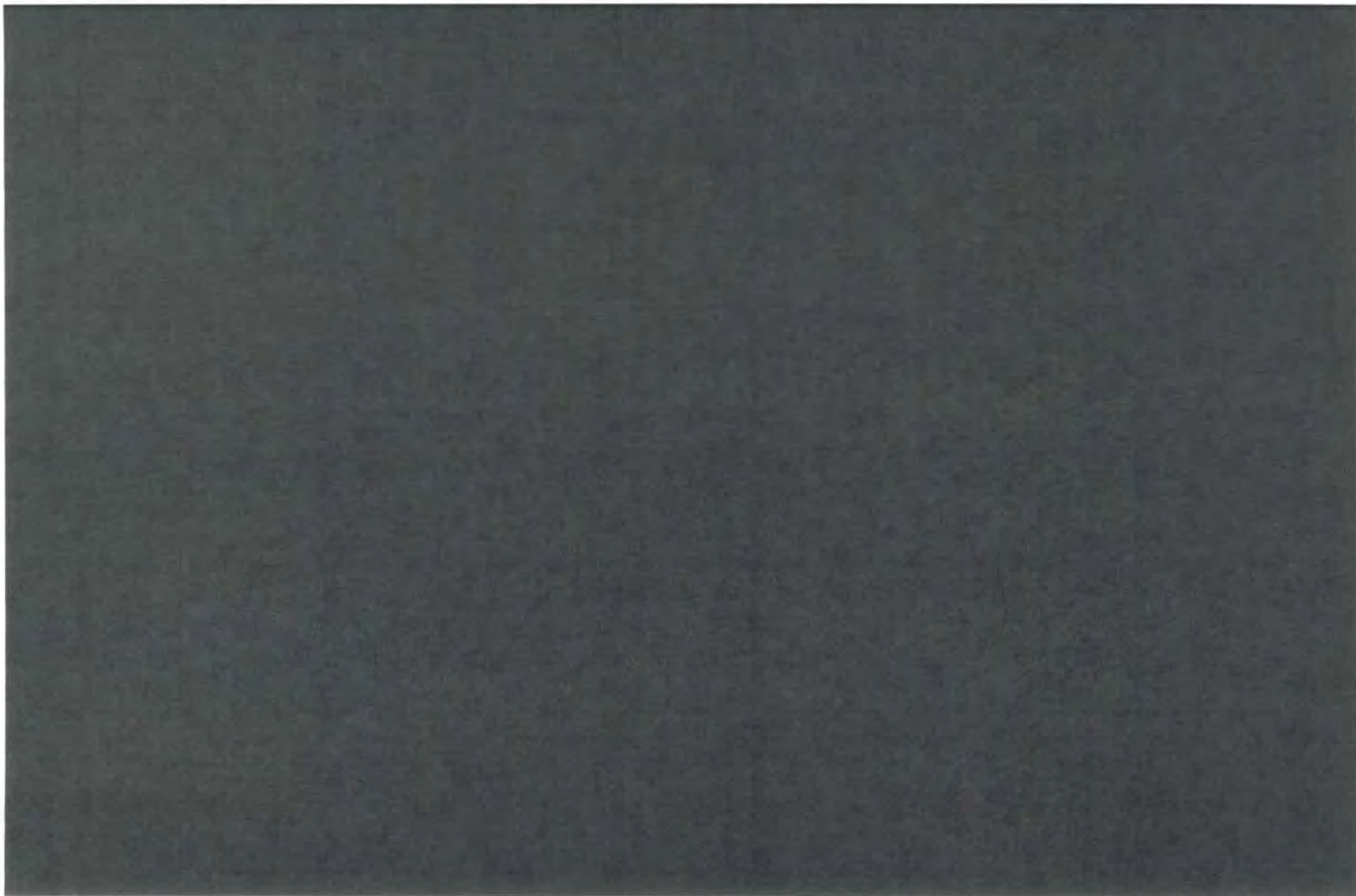
Major Outages

The table below lists the major outages for years 2022, 2023, and 2024 based on the outage duration measured in MVA minutes. Georgia Power is defining a major outage as an outage with event duration greater than 10,000 MVA minutes.



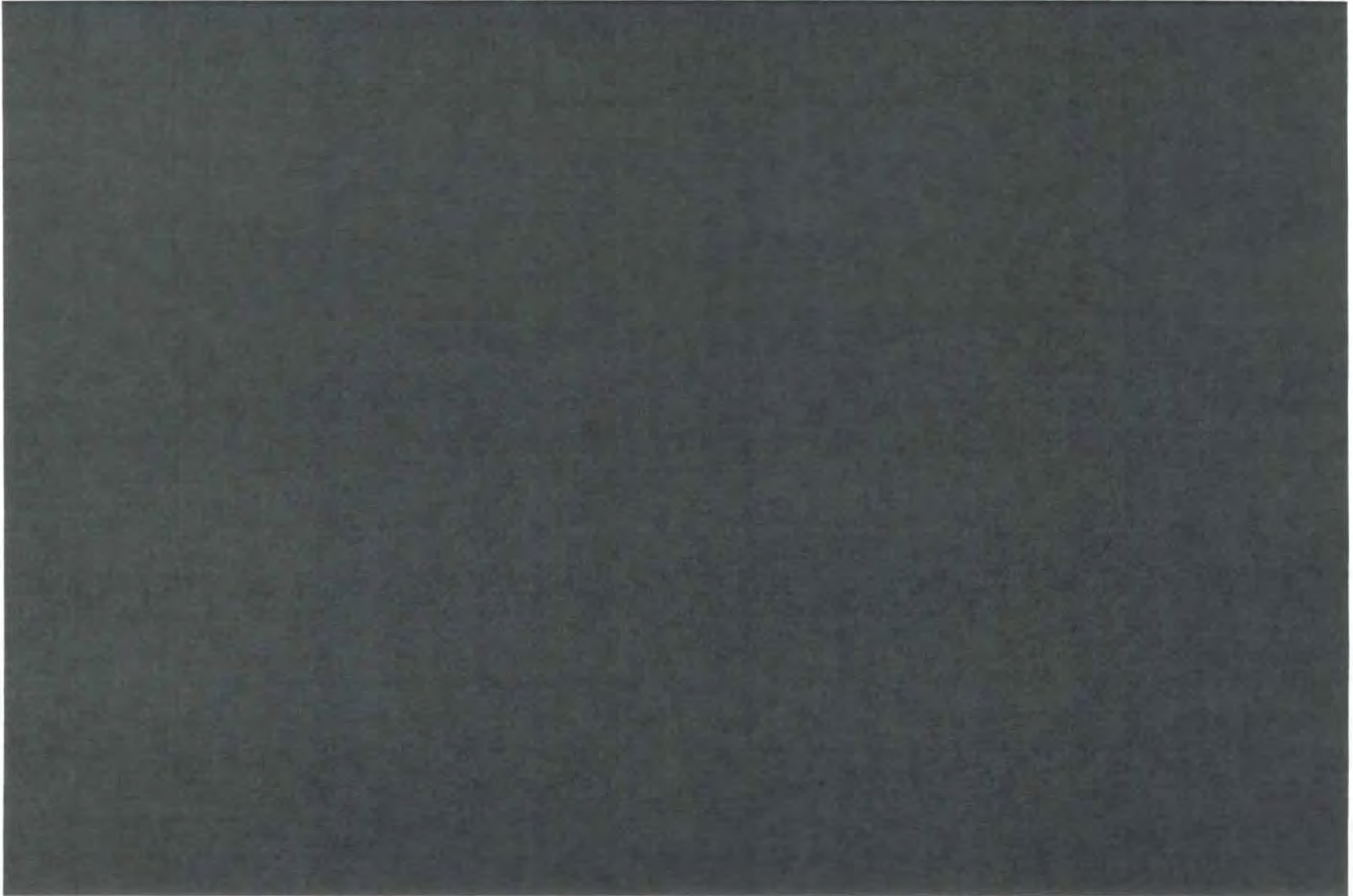
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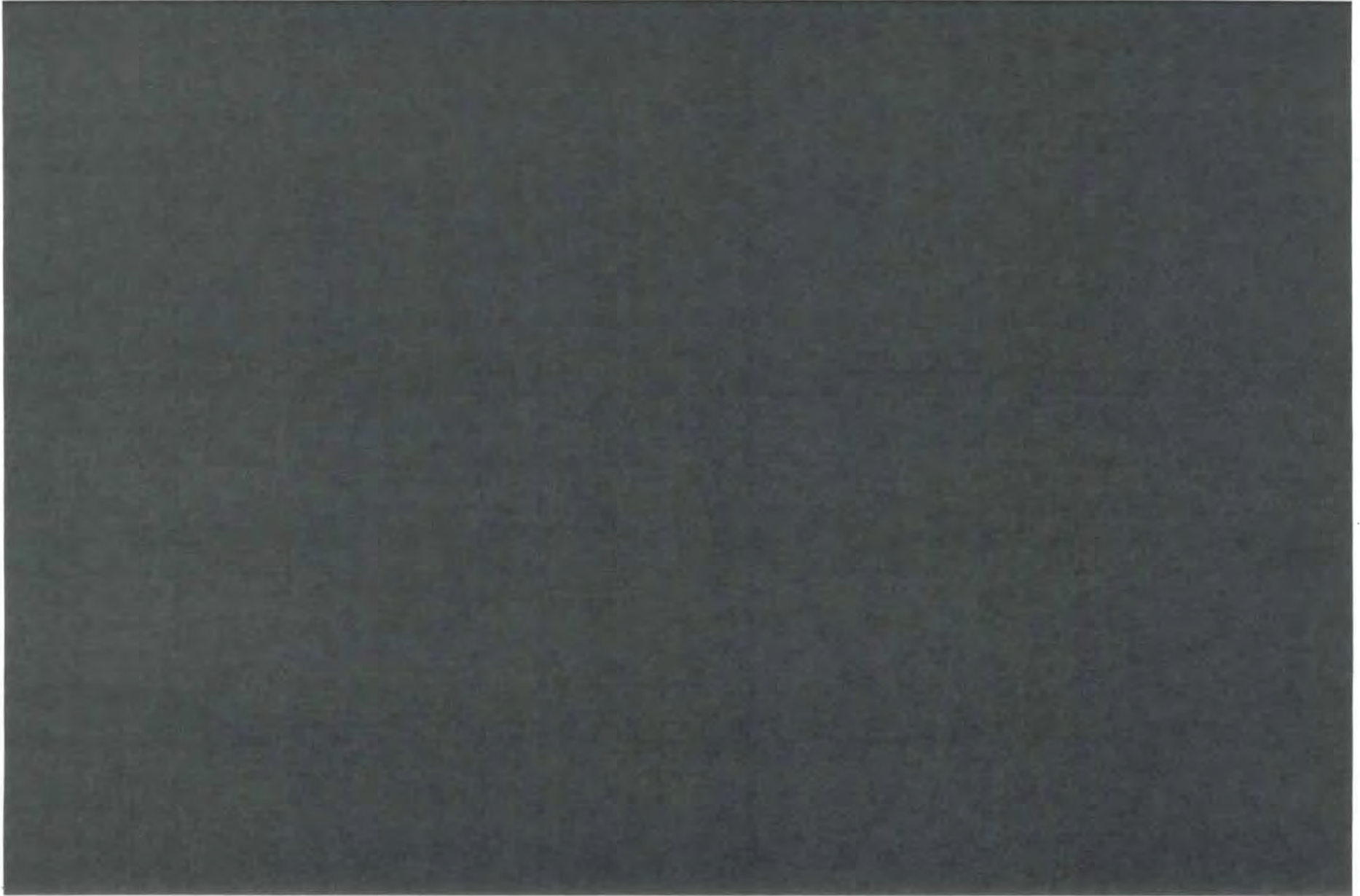
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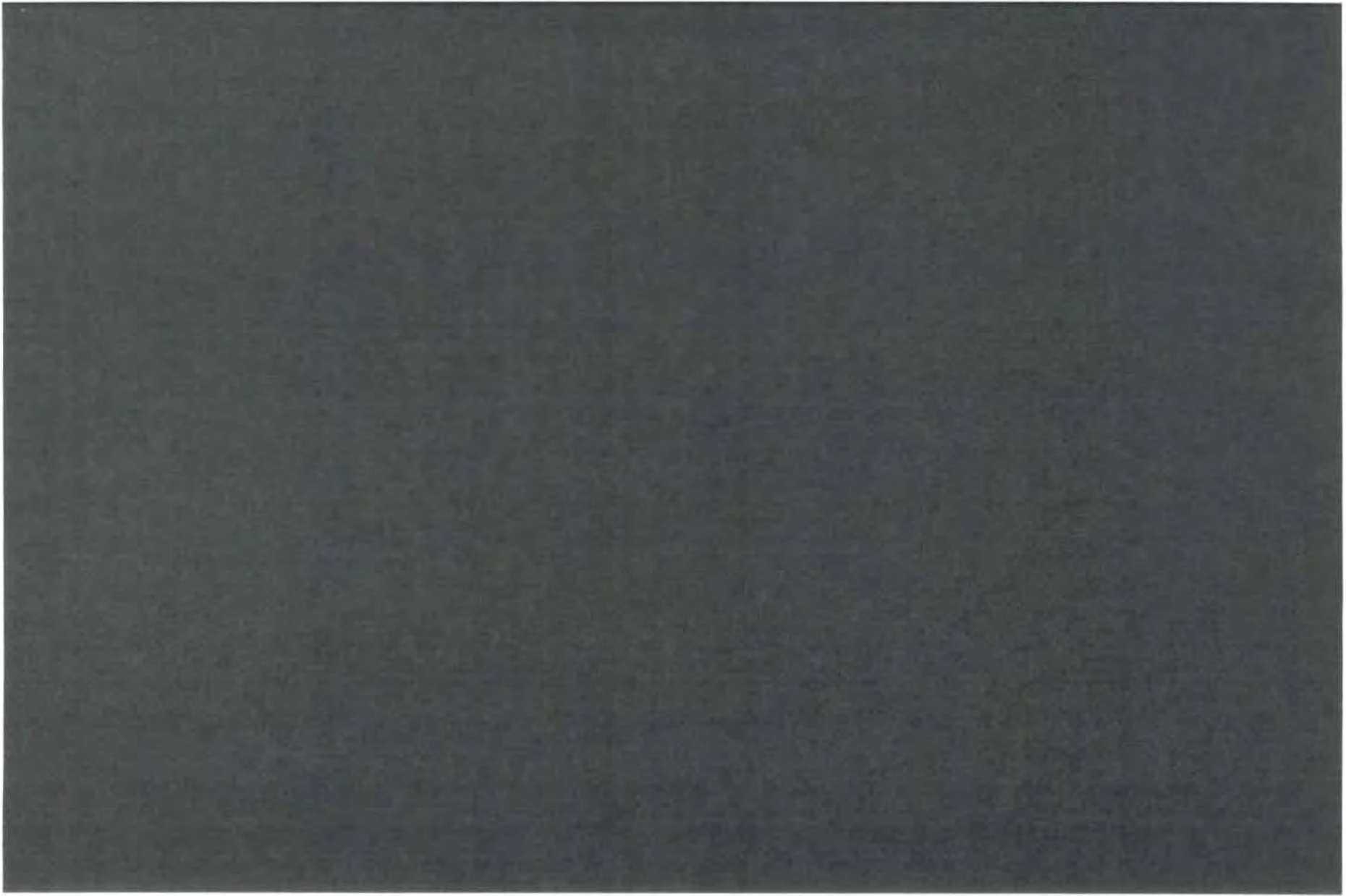
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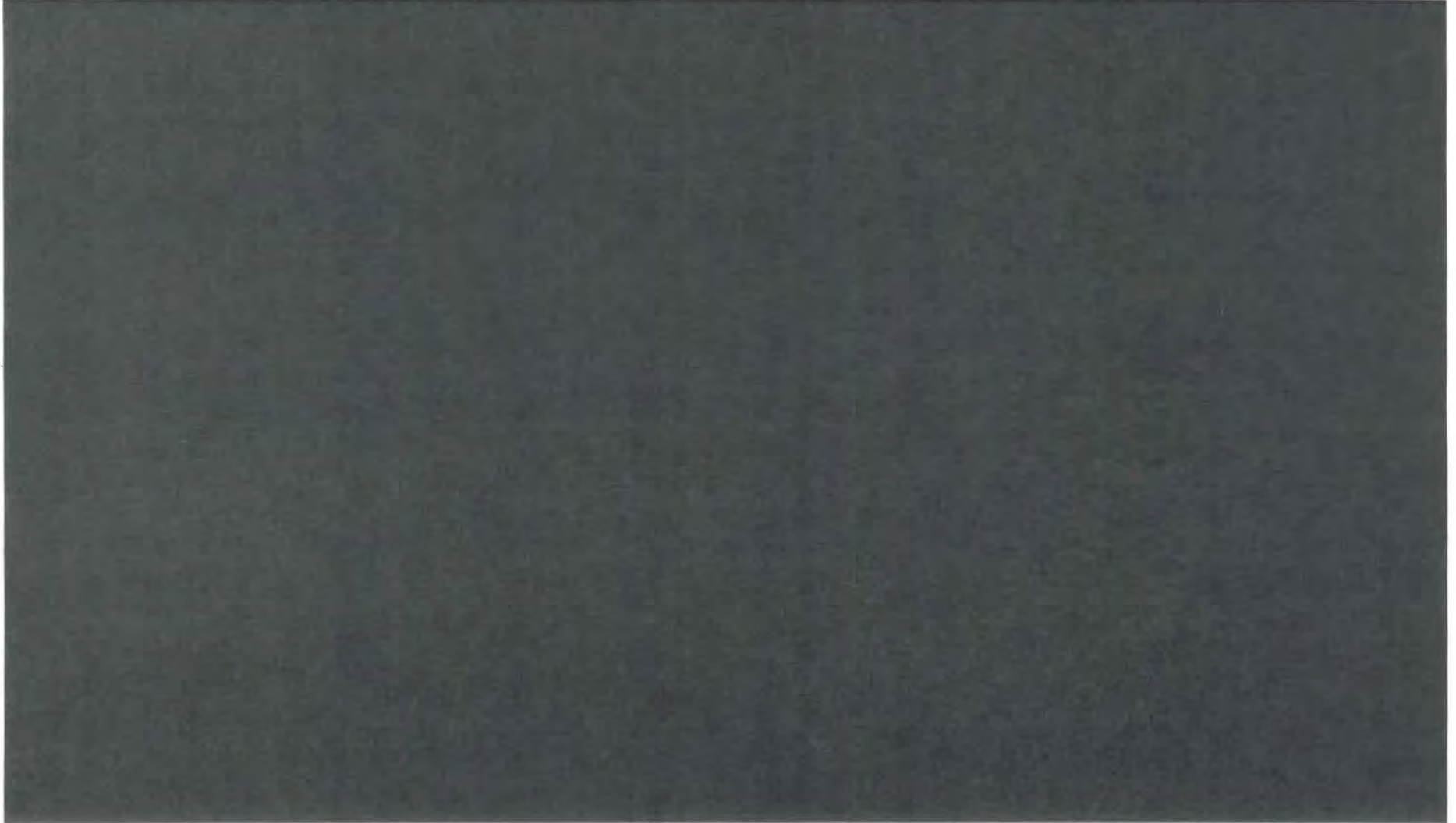
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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 56002**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2025 Integrated Resource Plan ("2025 IRP"), filed in Docket No. 56002, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 3, which contains confidential details regarding current and future transmission projects (the "Information") that is a trade secret of Georgia Power and Southern Company and their affiliates.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive cost information related to the prices Georgia Power has estimated for transmission equipment and specific details related to the Company's transmission infrastructure. Public dissemination of the Information would allow Georgia Power's competitors and suppliers to have access to the costs paid by the Company and insight into the Company's transmission planning process. Access to the Information would also allow competitors to gain specific insight into the Company's technical analysis regarding planned projects. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure the pricing for competing products based on the Information. In the event the Information was released, it is quite likely that suppliers would use the Information to set the floor in establishing their own prices, thus artificially and inefficiently setting a market price that may not be representative of the best cost that the market could offer. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power. Finally, the Information includes sensitive details concerning Georgia Power's transmission infrastructure that must be protected from public disclosure in the interests of system security and reliability. Such portions of the Information contain Critical Energy Infrastructure Information as defined by the Code of Federal Regulations Section 388.113.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company affiliate personnel are granted access to the Information and receive access on a "need to know" basis only. Any parties outside the Company who would be granted access to the Information would be required to sign confidentiality agreements.

EXHIBIT

tabbies

GIPLSF-7B

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Michael B. Robinson, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 3 of the Company's 2025 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2018).



Michael B. Robinson
Vice President, Grid Transformation
Georgia Power Company

Subscribed and sworn to before me this 6 day of Jan, 2025.



Notary Public

My Commission expires



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A. Georgia ITS 10 Year Expansion Plan Projects List

Table 2 Georgia ITS 10 Year Plan Project List below briefly lists projects in the 10 Year Expansion Plan (details for each project are in later sections).

Table 2 Georgia ITS 10 Year Plan Project List

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
219	2025	19523	SAV: CC - HYUNDAI MOTORS SAVANNAH AKA. PROJECT EA	1/1/2025	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2025	18670	GTC: BANKS CROSSING - POND FORK 115 KV	5/1/2025	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2025	18492	MITCHELL - NORTH TIFTON 230KV RECONDUCTOR	5/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2025	19676	ADAMSVILLE - JACK MCDONOUGH 230KV LINE REBUILD	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2025	18800	ECHECONNIE-WELLSTON 115KV REBUILD	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2025	19187	GRID - BREMEN - CROOKED CREEK (APC) 115 KV PROJECT	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2025	18153	GTC: BONAIRE PRI- ECHECONNIE 115 KV PARTIAL REBUILD	6/1/2025	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
218	2025	20342	GTC: CAMDEN INDUSTRIAL PARK 230/115KV NEW SUBSTATION	6/1/2025	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2025	20590	GTC: EATONTON PRIMARY - LICK CREEK 115KV LINE SWITCH REPLACEMENT	6/1/2025	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
218	2025	11821	JESUP - LUDOWICI PRIMARY 115KV REBUILD	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2025	13753	MEAG: ALCOVY ROAD - SKC 115 KV RECONDUCTOR	6/1/2025	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2025	13787	MEAG: AULTMAN ROAD - BONAIRE PRIMARY 115 KV REBUILD	6/1/2025	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2025	20464	NORCROSS 230KV BUS 1-3 SERIES BUS TIE BREAKER INSTALLATION	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
216	2025	19631	PINE GROVE PRIMARY 115 KV DUAL STAGE CAPACITOR BANK	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2025	20067	SAV: DEPTFORD - MAGNOLIA 115KV RECONDUCTOR	6/1/2025	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2025	20466	SMART VALVE INSTALLATION	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
218	2025	21046	THALMANN AND COLERAIN 230 KV LINE RELAY PANEL UPGRADES	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2025	20431	VILLA RICA LOW SIDE BREAKER	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
218	2025	20684	CAMDEN INDUSTRIAL PARK (GPC)	6/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2025	18774	GTC: HEARD COUNTY - TENASKA 500KV (SECOND LINE)	12/1/2025	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2025	18889	JEFFERSON STREET#3 - NORTHWEST (WHITE) 115 KV RECONDUCTOR	12/1/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2025	20326	ANTHONY SHOALS STATCOM SYSTEM	12/31/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2025	20152	CC - CASS PINE- HILL VIEW 230 KV LINE- CC IMPROVEMENTS	12/31/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2025	20175	CC - PROJECT CHRONOS-SK/HYUNDAI	12/31/2025	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2025	20010	GTC: ANTHONY SHOALS - WASHINGTON 115 KV LINE REBUILD	12/31/2025	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2025	17075	SAV: LITTLE OGEECHEE 230-115KV: RELAY MODERNIZATION	12/31/2025	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2026	18691	GTC: LIZARD LOPE - WESTOVER 115 KV NEW LINE	3/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	20018	CC - QTS FAYETTEVILLE TRANSMISSION NEEDS	4/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
208	2026	19597	ADAMSVILLE - BUZZARD ROOST 230KV REBUILD AND JUMPER UPGRADE	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2026	18960	BLANKETS CREEK – WOODSTOCK 115KV LINE REBUILD	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2026	20243	CC - GARRETT ROAD SWITCHING STATION - TRAE LANE	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	20216	CC - STONEWALL TELL ROAD (TA REALTY)	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2026	18679	DU: EAST DALTON - OOSTANAULA 115KV REBUILD	6/1/2026	DU	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	20491	EAST POINT RELAY MODERNIZATION	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2026	16007	FENWICK STREET - SAND BAR FERRY 115KV (RECONDUCTOR/REBUILD)	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2026	20516	GOAT ROCK 230KV SWITCH, JUMPER, & LINE TRAP REPLACEMENT	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2026	19618	GORDON-N DUBLIN 115KV (GORDON-ENGL MCI J) REBUILD	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2026	21139	GRADY - MORROW (WHITE) 115KV REBUILD	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2026	20474	GRADY 230/115KV RELAY MODERNIZATION	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2026	19706	GRID - GAINESVILLE #2 EQUIPMENT REPLACEMENT	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2026	21137	GTC: CONYERS - CORNISH MOUNTAIN 115KV LINE UPGRADE	6/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2026	19334	GTC: LAGRANGE - NORTH OPELIKA 230 KV	6/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2026	20015	GTC: MORNING HORNET 2ND 230/115 KV BANK & THUMBS UP 115KV TL	6/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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214	2026	19999	GTC: ROBINS SPRING BUS REPLACEMENT	6/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2026	20001	GTC: ROBINS SPRING CAPACITOR BANK INSTALLATION	6/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2026	19636	HAMMOND - WEISS DAM 115KV LINE REBUILD	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2026	20512	KATHLEEN AREA IMPROVEMENTS	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2026	20490	KLONDIKE RELAY MODERNIZATION	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2026	19598	MEAG: DRESDEN - LAGRANGE PRIMARY 230KV UPGRADE & JUMPERS	6/1/2026	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2026	20270	MEAG: RAY PLACE RD - WASHINGTON #3	6/1/2026	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2026	20271	MEAG: RAY PLACE RD - WASHINGTON (WASHINGTON - WASHINGTON 3)	6/1/2026	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	20300	MORROW 115KV RELAY UPGRADE	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2026	18690	PALMYRA REACTOR REMOVAL	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2026	20066	SAV: BOULEVARD - DEPTFORD 115KV RECONDUCTOR	6/1/2026	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2026	19966	SAV: CC - BIG OGEECHEE 500/230KV (CC NETWORK IMPROVEMENTS)	6/1/2026	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2026	20277	SAV: MCINTOSH - PURRYSBURG 230KV REACTORS	6/1/2026	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2026	20489	SCOTTDALE RELAY MODERNIZATION	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	17900	UNION CITY - YATES 230 KV WHITE LINE REBUILD	4/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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208	2026	20691	UNION CITY - YATES 230KV (WHITE) SWITCH AND TRAP REPLACEMENT	6/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2026	20223	CC - PROJECT PAYTON BAINBRIDGE	6/30/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	21022	OHARA BREAKER REPLACEMENT	10/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	20668	DRESDEN LINE PROTECTIVE RELAYING	12/1/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2026	20874	GTC: BARNESVILLE PRIMARY- BARNESVILLE #1 115KV RECONDUCTOR	12/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	20273	GTC: DRESDEN 500KV BUS EXPANSION	12/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2026	20002	GTC: GORDON - SANDERSVILLE #1 115KV LINE REBUILD	12/1/2026	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2026	20151	CC - CASS PINE 230/25 NEW SUB - QCELLS - CC IMPROVEMENTS	12/31/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2026	19287	GRADY-WEST END 115KV REBUILD	12/31/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2026	19363	MORROW - MOUNTAIN VIEW 115 KV REBUILD	12/31/2026	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2027	18832	MEAG: FORTSON 230KV SUBSTATION MODERNIZATION	1/13/2027	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2027	20509	CC - EMBLEM RIVERSIDE CUSTOMER SUB (FLEXENTIAL)	3/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2027	19635	GTC: HICKORY LEVEL - VILLA RICA 230KV LINE RECONDUCTOR	5/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2027	19601	MORROW - YATES COMMON 115KV LINE UPGRADE	5/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2027	15879	POSSUM BRANCH - YATES COMMON 115KV REBUILD (YATES TO CLEM)	5/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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208	2027	20771	CC - GULLATT ROAD TRANSMISSION IMPROVEMENTS	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2027	18736	CC - MICROSOFT - SHUGART (CC006)	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2027	20781	CC - SUMMER LAKE - VILLA RICA 230KV REBUILD (CC IMPROVMENT)	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2027	20736	CC - TA REALTY ELLENWOOD NETWORK IMPROVEMENTS	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2027	20234	DOYLE - LG&E MONROE 230KV - JACKS CREEK LOOP IN	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2027	20858	GTC: ADAMSVILLE - BUZZARD ROOST 230KV REBUILD	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2027	20776	GTC: DOUGLASVILLE - VILLA RICA 230KV REBUILD (CC IMPROVEMENT)	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2027	20778	GTC: DOYLE - WINDER PRIMARY 230KV LINE JUMPER REPLACEMENT	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2027	19358	GTC: EAST MOULTRIE - HIGHWAY 112 230 KV LINE	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2027	09662	GTC: EAST WALTON 500/230KV PROJECT	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2027	20505	GTC: GARRETT RD - V. RICA 230KV LINE RECONDUCTOR (CC NET IM)	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2027	19622	GTC: RIDDLEVILLE BUS REPLACEMENT	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2027	19606	GTC: SKC 115KV BUS AND JUMPER REPLACEMENT	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2027	20020	GTC: SOUTH HAZLEHURST - NEW LACY 230KV LINE	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2027	20506	GTC: SWITCH WAY - THORNTON ROAD 230KV LINE REBUILD	6/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
218	2027	18668	JESUP - OFFERMAN 115KV REBUILD	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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202	2027	10143	LAWRENCEVILLE - WINDER 115KV LINE REBUILD	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2027	10481	LAWRENCEVILLE - WINDER PRIMARY 230KV LINE REBUILD	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2027	20264	MEAG: RAY PLACE RD - WARRENTON PRIMARY	6/1/2027	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2027	19248	SANDERSVILLE #1 - WADLEY PRI. 115KV REBUILD/RECONDUCTOR	6/1/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2027	20785	SAV: GOSHEN (SAV) - KRAFT 115KV LINE REBUILD	6/1/2027	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2027	20065	SAV: GOSHEN (SAV) - MCINTOSH 115KV LINE REBUILD	6/1/2027	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2027	20717	CC - TOMOCHICHI 500/230KV SOLUTION (CC NETWORK IMPROVEMENTS)	7/15/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2027	18573	GRID - ARKWRIGHT - LLOYD SHOALS 115KV	7/30/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2027	20591	GTC: EATONTON PRIMARY (035591) - LICK CREEK 115KV REBUILD	12/1/2027	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2027	17977	ATHENA - EAST WATKINSVILLE 115 KV (REBUILD)	12/31/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2027	20150	CC - HILL VIEW & GRASSY HOLLOW SUB - CC IMPROVEMENTS	12/31/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2027	20024	DYER ROAD - EAST ROANOKE 115KV (REBUILD)	12/31/2027	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2028	19997	AULTMAN ROAD-PERRY 115KV LINE REBUILD	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2028	20797	CC - EAST VILLA RICA AREA SWITCHING STATION (CC IMPROVEMENT)	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2028	20774	CC - VILLA RICA UPGRADES (CC NETWORK IMPROVEMENTS)	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2028	21048	FITZGERALD - PITTS 115 KV LINE REBUILD	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2028	08458	GTC: BARNESVILLE - SOUTH GRIFFIN 230KV PROJECT	6/1/2028	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2028	20503	GTC: BARNEYVILLE - EAST MOULTRIE 115KV NEW LINE	6/1/2028	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2028	20873	GTC: BONAIRE PRIMARY 500/230KV XFMR REPLCMNT & RELAY MOD	6/1/2028	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2028	19992	GTC: BOSTWICK - EAST SOCIAL CIRCLE 230KV RECONDUCTOR	6/1/2028	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2028	20777	JACK MCDONOUGH - NORTHWEST (BLACK) 230KV RECONDUCTOR	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2028	19629	MEAG: BRUMBLEY CREEK - SOUTH BAINBRIDGE 115KV REBUILD	6/1/2028	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2028	19630	MEAG: THOMASVILLE 230/115KV AUTOBANK REPLACEMENT	6/1/2028	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2028	20482	PITTMAN ROAD - WEST POINT DAM (USA) 115KV REBUILD	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2028	20656	PLANT YATES BREAKER AND HALF STATION	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2028	20783	SAV: COLEMAN - DEAN FOREST 115KV LINE REBUILD	6/1/2028	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2028	20407	SAV: MAGNOLIA - TRUMAN PARKWAY 115KV REBUILD	6/1/2028	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2028	21069	SMART VALVES AT EAST VILLA RICA SWITCHING STATION	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2028	20768	SOUTH MACON 115KV BUSES 1 & 2 REPLACEMENT	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2028	20274	UNION CITY - YATES 230KV (BLACK) LINE REBUILD	6/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2028	13166	FIRST AVENUE - NORTH COLUMBUS 115KV LINE REBUILD	12/1/2028	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2028	20586	GTC: NORTH DUBLIN 230/115KV TRANSFORMERS AND BUS-TIE BREAKER	12/1/2028	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2029	21062	ASHLEY PARK-WANSLEY 500KV	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2029	10222	BLAKELY PRIMARY - HUCKLEBERRY 115KV REBUILD	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2029	21047	BROADWAY - ECHECONNIE 115 KV LINE REBUILD	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2029	16887	BUTLER - THOMASTON 230KV LINE CONVERSION	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2029	21036	BUZZARD ROOST - FACTORY SHOALS 230KV NEW LINE	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2029	21142	CONYERS - KLONDIKE 230 KV SECOND LINE	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2029	21138	GLENWOOD SPRINGS - PORTERDALE PRIMARY 230KV LINE SWITCH REPL	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2029	21112	GTC: BARNESVILLE PRIMARY - THOMASTON 230KV	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2029	10814	GTC: BAY CREEK 230/115KV SECOND AUTO TRANSFORMER	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2029	21140	GTC: BONAIRE PRIMARY - EASTMAN PRIMARY 115 KV LINE REBUILD	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2029	20849	GTC: CLIFTONDALE - LINE CREEK 230KV LINE	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2029	19950	GTC: DRESDEN - TALBOT 500KV LINE	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2029	20760	GTC: HOPEWELL 230/115 KV BANK A	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2029	21123	GTC: TENASKA - WANSLEY 500KV NEW LINE	6/1/2029	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
206	2029	21141	LLOYD SHOALS - PORTERDALE PRIMARY 115KV REBUILD	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2029	20285	LOWER RIVER - WEBB (APC) 115KV RECONDUCTOR	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
212	2029	19621	MCEVER ROAD - SHOAL CREEK 115KV REBUILD	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
218	2029	20346	MCMANUS - WEST BRUNSWICK 115KV REBUILD	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2029	17706	MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV REBUILD	6/1/2029	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2029	11051	MEAG: SLAPPEY DRIVE - WESTOVER 115KV LINE REBUILD	6/1/2029	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2029	20757	NORCROSS - NORTH DRUID HILLS 115KV REBUILD	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2029	21006	SAV: BOULEVARD - MAGNOLIA 115 KV LINE REBUILD	6/1/2029	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2029	21023	SAV: DEAN FOREST - LITTLE OGEECHEE 230 KV REBUILD	6/1/2029	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2029	20989	SAV: RICE HOPE NEW AUTO TRANSFORMER	6/1/2029	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2029	13628	SOUTH BAINBRIDGE - SINAI (FPL) 115KV LINE RECONDUCTOR	6/1/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2029	20248	BAY CREEK - CONYERS 230KV REBUILD	12/31/2029	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2030	21129	ANNISTON - HAMMOND 230KV LINE	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	20764	ATKINSON - NORTHSIDE DRIVE 115KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	20761	ATKINSON - NORTHWEST 115KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	21130	CC - NORTH GEORGIA DATA NETWORK UPGRADES	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	10478	CORNELIA - TALLULAH LODGE 115KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	18669	DU: DAWSON CROSSING - NELSON (WHITE) 115 KV REBUILD	6/1/2030	DU	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	21097	EAST POINT - TRIBUTARY 230KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
208	2030	20480	EAST POINT - UNION CITY 230KV BLACK LINE RECONDUCTOR	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2030	19627	ECHECONNIE-WELLSTON 115KV LINE REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2030	21063	FARLEY (APC)-TAZEWELL 500KV	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	12120	GAINESVILLE #2 - MCEVER ROAD 115 KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2030	20298	GLENWOOD SPRINGS - LAKE OCONEE 115KV LINE REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2030	21128	GOAT ROCK REACTORS INSTALLATION	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2030	19996	GOLDENS CREEK - WARRENTON PRIMARY 230KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2030	20428	GORDON-SANDERSVILLE #1 115KV LINE REBUILD (DEEPSTEP-SAND #6)	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2030	21116	GOSHEN AREA STRATEGIC SOLUTION	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2030	21073	GTC: BIG SMARR - TOMOCHICHI 500KV	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	21014	GTC: BUZZARD ROOST - CAVENDER DRIVE 230KV NEW LINE	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	21013	GTC: CAVENDER DRIVE 500/230KV AUTOBANK	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	20375	GTC: EAST WATKINSVILLE 230 KV STATION MODIFICATION	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	21111	GTC: HARTWELL DAM - HARTWELL ENERGY 230KV SERIES REACTORS	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	21113	GTC: HARTWELL ENERGY - MIDDLE FORK 230KV LINE	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	21131	GTC: POND FORK - MIDWAY 115KV LINE	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2030	21077	GTC: ROCKVILLE - TIGER CREEK - WARTHEN 500KV LINES	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2030	21076	GTC: TALLBOT #2 - TAZEWEEL 500KV LINE	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2030	21094	GTC: TIGER CREEK- ROCKVILLE-NORTH SPA 230KV PROJECT	6/1/2030	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	20789	JEFFERSON ROAD - WINDER PRIMARY 115KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2030	20284	KETTLE CREEK PRIMARY - PINE GROVE PRIMARY 115KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2030	21118	MEAG: ATHENA - WARRENTON 230KV CONVERSION	6/1/2030	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	20857	NEW CAVENDER DRIVE - TRIBUTARY 230KV LINE	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2030	21093	NORTH SPA 230KV STRATEGIC PROJECT	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2030	19995	TALLULAH LODGE - TOCCOA 115 KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
201	2030	21098	TRIBUTARY - THORNTON RD 230KV REBUILD	6/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2030	20160	THOMASTON 230 NEW BUILD SUB	11/1/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2030	18848	BAINBRIDGE TRANSMISSION: EAST RIVER ROAD, EAST BAINBRIDGE	12/31/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2030	19626	GLENWOOD SPRINGS 115KV CAP BANK	12/31/2030	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
208	2031	20690	EAST POINT - UNION CITY (WHITE) 230KV REBUILD	5/1/2031	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2031	19632	AVERY - HOPEWELL 115KV RECONDUCTOR	6/1/2031	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
211	2031	10811	BOWEN #10 500/230KV AUTOBANK REPLACEMENT	6/1/2031	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2031	20756	HATCH - WADLEY 500 KV LINE STRATEGIC PROJECT	6/1/2031	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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214	2031	21099	MEAG: PIO NONO 230/115KV AREA SOLUTION	6/1/2031	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
213	2032	21114	MEAG: SOUTH GRIFFIN 230/115KV BANK #5	6/1/2032	MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2032	20784	SAV: COLEMAN - MELDRIM 115KV LINE REBUILD	6/1/2032	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
214	2033	20767	ARKWRIGHT BUS AND JUMPER REPLACEMENT	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
202	2033	20758	BAY CREEK - CONYERS 230KV LIMITING ELEMENT REPLACEMENT	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2033	20793	EVANS PRIMARY - THURMOND DAM (USA) #5 115KV REBUILD	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2033	20794	EVANS PRIMARY - THURMOND DAM (USA) #6 115KV REBUILD	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	12217	GTC: CENTER PRIMARY - CLARKSBORO 230 KV REBUILD	6/1/2033	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	20773	GTC: CLARKSBORO - WINDER PRIMARY 230KV REBUILD	6/1/2033	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	12147	GTC: EAST SOCIAL CIRCLE - SNELLVILLE 230KV EQUIPMENT UPGRADE	6/1/2033	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	21075	GTC: EAST WALTON - MIDDLE FORK 500KV	6/1/2033	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	20791	GTC: SHOAL CREEK - SOUTH HALL 230KV REBUILD	6/1/2033	GTC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	21053	MCEVER ROAD - SHOAL CREEK 115KV REBUILD PHASE III	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2033	09661	MCGRAU FORD - MIDDLE FORK 500KV LINE PROJECT	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2033	20796	SAV: MELDRIM BANK D REPLACEMENT	6/1/2033	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2033	14222	THOMSON PRIMARY 230/115KV SECOND TRANSFORMER	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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202	2033	20759	WINDER PRIMARY 230KV BUS 1-2 PARALLEL BUS-TIE INSTALLATION	6/1/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
216	2033	10487	PINE GROVE PRIMARY - WEST VALDOSTA 115 KV RECONDUCTOR	12/31/2033	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
212	2034	18700	DAWSON CROSSING - GAINESVILLE #1 115 KV	6/1/2034	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
219	2034	20787	SAV: LITTLE OGEECHEE 230/115KV BANK REPLACEMENT	6/1/2034	SAV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
215	2034	17993	EVANS PRIMARY - THOMSON PRIMARY 115KV REBUILD	12/31/2034	GPC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total						REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 56002**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2025 Integrated Resource Plan ("2025 IRP"), filed in Docket No. 56002, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 3, which contains confidential details regarding current and future transmission projects (the "Information") that is a trade secret of Georgia Power and Southern Company and their affiliates.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive cost information related to the prices Georgia Power has estimated for transmission equipment and specific details related to the Company's transmission infrastructure. Public dissemination of the Information would allow Georgia Power's competitors and suppliers to have access to the costs paid by the Company and insight into the Company's transmission planning process. Access to the Information would also allow competitors to gain specific insight into the Company's technical analysis regarding planned projects. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure the pricing for competing products based on the Information. In the event the Information was released, it is quite likely that suppliers would use the Information to set the floor in establishing their own prices, thus artificially and inefficiently setting a market price that may not be representative of the best cost that the market could offer. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power. Finally, the Information includes sensitive details concerning Georgia Power's transmission infrastructure that must be protected from public disclosure in the interests of system security and reliability. Such portions of the Information contain Critical Energy Infrastructure Information as defined by the Code of Federal Regulations Section 388.113.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company affiliate personnel are granted access to the Information and receive access on a "need to know" basis only. Any parties outside the Company who would be granted access to the Information would be required to sign confidentiality agreements.



Michael B. Robinson, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 3 of the Company's 2025 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2018).



Michael B. Robinson
Vice President, Grid Transformation
Georgia Power Company

Subscribed and sworn to before me this 6 day of Jan, 2025.



Notary Public

My Commission expires:



Appendix 2C-1: List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Winters Branch - Add 4th TX - DEV (Position #4)	230	Aug-24	VA	0.3
Pearsons 230kV Switch Replacements EOL	230	Aug-24	VA	0.5
Altair 230kV Delivery - NOVEC (Microsoft Leesburg) (Belmont-Altair-Brambleton)	230	Sep-24	VA	51.9
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Sep-24	VA	151.0
Youngs Branch - Add 2nd TX - DEV	230	Sep-24	VA	0.8
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Cemetery Road Sub - 115kV Delivery - DEV	115	Oct-24	VA	5.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Oct-24	VA	13.9
Clifton Forge TX#2 EOL	138/230	Nov-24	VA	3.0
Line #2008 Uprate - Takeoff to Lincoln Park	230	Nov-24	VA	4.5
Line #2008 Uprate - Takeoff to Walney	230	Nov-24	VA	2.0
Gretna 69kV Delivery - Add 2nd TX - DEV	69	Nov-24	VA	0.6
Line #2008 Uprate - Cub Run to Walney	230	Nov-24	VA	2.0
Line #2242 Uprate - Dulles to Lincoln Park	230	Nov-24	VA	6.0
230kV Line Extension Cannon Branch to Winters Branch	230	Dec-24	VA	22.0
Trappe Rock 230kV Delivery - NOVEC	230	Dec-24	VA	16.2
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Dec-24	VA	0.8
Farmville 230-115kV Transformer #5 EOL Replacement	115/230	Dec-24	VA	6.4
NIVO - Bus Expansion	230	Dec-24	VA	12.0
Magruder Sub - Upgrade 115/34.5kV TX#1 - DEV	115	Dec-24	VA	1.0
Northstar 230kV Delivery - NOVEC	230	Dec-24	VA	10.0
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild - 1.7 mile Double Circuit Sections with Line #2056 (Hornertown-Hathaway)	115	Dec-24	NC	3.4
Metcalf Sub 115kV Delivery - TX #1 Upgrade - DEV	115	Dec-24	VA	0.6
Harrisonburg Transformer#1 Upgrade	115	Dec-24	VA	0.3
NIT Industrial - New 230kV Delivery Point (DEV)	230	Dec-24	VA	5.0
Line #2010 Underground Relocation	230	Dec-24	VA	40.0
Line #100 (Locks to Harrowgate) Partial Rebuild	115	Dec-24	VA	9.1
Bishop Substation -115 kV Delivery (MEC) - Ridge DP	115	Mar-25	VA	15.0
Jeffress Sub - 115 kV Delivery (MEC) - Lakeside DP	115	Feb-25	VA	15.5

DOMINION VIRGINIA 2024 IRP*

EXHIBIT

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Appendix 2C-1: List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Nimbus 230kV Delivery - DEV (Beaumeade-Nimbus-Buttermilk)	230	Apr-25	VA	12.0
Line #141 (Balcony Falls to Skimmer) & Line#28 (Balcony Falls to Cushaw) EOL and Balcony Falls Substation Rebuild	115	May-25	VA	55.0
DTC 230kV Delivery - DEV (Extension of Line #2143 (Beaumeade-BECO) to DTC)	230	Jun-25	VA	60.3
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2186 Uprate - Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2218 Uprate-Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Rixlew 230 kV Delivery - NOVEC	230	Jun-25	VA	10.0
Lost City - New 230 kV Delivery - DEV	230	Jul-25	VA	10.2
Line #105 (Tarboro-Parmelee) EOL Rebuild	115	Jul-25	NC	26.0
Partial Line#5 Retirement (Fork Union to Cunningham DP)-line 1049 retirement	115	Aug-25	VA	5.5
Interconnection 230kV Delivery - DEV (Beaumeade-Interconnection-Nimbus)	230	Sep-25	VA	32.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Oct-25	VA	15.3
Ocean Court 230kV Delivery - DEV	230	Oct-25	VA	12.7
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.2
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Stratus 230kV Delivery - DEV - (CPR changed to Engineering)	230	Dec-25	VA	24.0
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Dec-25	VA	1.0
Hornbaker 230kV Delivery - NOVEC (Avanti) (Liberty-Hornbaker-Pioneer)	230	Apr-26	VA	45.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Bear Run Sub - Cub Run 230kV Expansion - NOVEC	230	Sep-26	VA	24.5
Wishing Star DP -NOVEC	230	Dec-26	VA	10.0
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.3
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Line #2008 Uprate - Loudoun to Takeoff	230	Aug-27	VA	4.6
Partial Line #83 EOL Rebuild	115	Mar-28	VA	23.0

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Winters Branch - Add 4th TX - DEV (Position #4)	230	Aug-24	VA	0.3
Pearsons 230kV Switch Replacements EOL	230	Aug-24	VA	0.5
Altair 230kV Delivery - NOVEC (Microsoft Leesburg) (Belmont-Altair-Brambleton)	230	Sep-24	VA	51.9
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Sep-24	VA	151.0
Youngs Branch - Add 2nd TX - DEV	230	Sep-24	VA	0.8
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Cemetery Road Sub - 115kV Delivery - DEV	115	Oct-24	VA	5.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Oct-24	VA	13.9
Clifton Forge TX#2 EOL	138/230	Nov-24	VA	3.0
Line #2008 Uprate - Takeoff to Lincoln Park	230	Nov-24	VA	4.5
Line #2008 Uprate - Takeoff to Walney	230	Nov-24	VA	2.0
Gretna 69kV Delivery - Add 2nd TX - DEV	69	Nov-24	VA	0.6
Line #2008 Uprate - Cub Run to Walney	230	Nov-24	VA	2.0
Line #2242 Uprate - Dulles to Lincoln Park	230	Nov-24	VA	6.0
230kV Line Extension Cannon Branch to Winters Branch	230	Dec-24	VA	22.0
Trappe Rock 230kV Delivery - NOVEC	230	Dec-24	VA	16.2
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Dec-24	VA	0.8
Farmville 230-115kV Transformer #5 EOL Replacement	115/230	Dec-24	VA	6.4
NIVO - Bus Expansion	230	Dec-24	VA	12.0
Magruder Sub - Upgrade 115/34.5kV TX#1 - DEV	115	Dec-24	VA	1.0
Northstar 230kV Delivery - NOVEC	230	Dec-24	VA	10.0
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild - 1.7 mile Double Circuit Sections with Line #2056 (Hornertown-Hathaway)	115	Dec-24	NC	3.4
Metcalf Sub 115kV Delivery - TX #1 Upgrade - DEV	115	Dec-24	VA	0.6
Harrisonburg Transformer#1 Upgrade	115	Dec-24	VA	0.3
NIT Industrial - New 230kV Delivery Point (DEV)	230	Dec-24	VA	5.0
Line #2010 Underground Relocation	230	Dec-24	VA	40.0
Line #100 (Locks to Harrowgate) Partial Rebuild	115	Dec-24	VA	9.1
Bishop Substation -115 kV Delivery (MEC) - Ridge DP	115	Mar-25	VA	15.0
Jeffress Sub - 115 kV Delivery (MEC) - Lakeside DP	115	Feb-25	VA	15.5

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch - Wakeman)	230	Mar-25	VA	3.9
EPG - Add 2nd and 3rd TX - DEV	230	Mar-25	VA	6.1
Nimbus 230kV Delivery - DEV (Beaumeade-Nimbus-Buttermilk)	230	Apr-25	VA	12.0
Line #141 (Balcony Falls to Skimmer) & Line#28 (Balcony Falls to Cushaw) EOL and Balcony Falls Substation Rebuild	115	May-25	VA	55.0
Davis Drive - 230kV Ring Bus Expansion - Line Extension W&OD Trail to Sub	230	Jun-25	VA	15.0
Clifton - Replace Overdutied L282 Breaker	230	Jun-25	VA	0.5
Install 115kV breaker at Stuarts Draft station	115	Jun-25	VA	5.0
Cumulus 230kV Delivery - Add 5th TX - DEV	230	Jun-25	VA	0.5
DTC 230kV Delivery - DEV (Extension of Line #2143 (Beaumeade-BECO) to DTC)	230	Jun-25	VA	60.3
Sherwood Transformer#2 Upgrade	115	Jun-25	VA	0.4
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2186 Uprate - Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Jun-25	VA	3.8
Line #2214 Uprate - Buttermilk to Roundtable	230	Jun-25	VA	4.8
Line #2218 Uprate-Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Line #2223 Uprate-Roundtable to Lockridge	230	Jun-25	VA	2.6
Rixlew 230 kV Delivery - NOVEC	230	Jun-25	VA	10.0
Line #249 (Carson to Locks) Rebuild and Energize TX #1	230	Jun-25	VA	25.6
Line #2151 Uprate - Railroad DP to Gainesville	230	Jun-25	VA	6.1
King and Queen 230kV Delivery - DEV	230	Jul-25	VA	1.9
Lost City - New 230 kV Delivery - DEV	230	Jul-25	VA	10.2
Varina SUB - add new TX (TX #2) - DEV	230	Jul-25	VA	0.5
Line #105 (Tarboro-Parmeale) EOL Rebuild	115	Jul-25	NC	26.0
Evans Creek Sub - Roanoke DP - 230kV Delivery-DEV_New 230kV Line from Tunstall to Evans Creek and Evans Creek to Raines	230	Aug-25	VA	30.0

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Raines Sub - Interstate DP - 230kV Delivery-DEV-New 230kV Line from Tunstall to Raines	230	Aug-25	VA	20.0
Tunstall Sub - Hillcrest DP - 230kV Delivery-DEV-New Unity 500/230kV Sub - Two New 230kV Lines from Unity to Tunstall	230/500	Aug-25	VA	140.0
Partial Line#5 Retirement (Fork Union to Cunningham DP)-line 1049 retirement	115	Aug-25	VA	5.5
Trident 230 kV Delivery - NOVEC (ARC West) (Gainesville-Trident-Wheeler)	230	Sep-25	VA	15.8
Interconnection 230kV Delivery - DEV (Beaumeade-Interconnection-Nimbus)	230	Sep-25	VA	32.0
Park Center 230kV Delivery - DEV	230	Sep-25	VA	10.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Oct-25	VA	15.3
Ocean Court 230kV Delivery - DEV	230	Oct-25	VA	12.7
Prentice Drive 230kV Delivery - DEV (CPR changed to Engineering)	230	Oct-25	VA	20.0
Southall (North Louisa (REB)) 230kV Delivery (Amazon AZ) - ODEC - Engineering	230	Nov-25	VA	55.0
Line #77 (Carolina-Roanoke Rapids Hydro) EOL Rebuild	115	Nov-25	VA	7.4
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.2
Install 2nd 115kV 33.67MVar Cap bank at Harrisonburg	115	Dec-25	VA	1.0
Walnut Creek 115kV switching station	115	Dec-25	VA	23.7
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Stratus 230kV Delivery - DEV - (CPR changed to Engineering)	230	Dec-25	VA	24.0
Brickyard 230kV Delivery - DEV	230	Dec-25	VA	6.6
Buttermilk 230kV Delivery - Add 3rd and 4th TX	230	Dec-25	VA	1.0
Butler Farm Sub - 230kV Delivery-DEV- Bailey DP - New Finneywood 500/230kV Sub a new 230kV Line (Butler Farm - Finneywood) and a new 230kV Line (Butler Farm - Clover)	230/500	Dec-25	VA	220.0
Line #2019 (Greenwich to Thalia) EOL Partial Rebuild	230	Dec-25	VA	14.3
Line #293 (Staunton to Valley) & Partial Line #83 EOL	230	Dec-25	VA	44.8
Line #202 - Clark to Idylwood Uprate	230	Dec-25	VA	8.0

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Line #2104 (Cranes Corner to Stafford) partial uprate	230	Dec-25	VA	28.3
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
500kV / 230kV Line Extension - Southern (Wishing Star to Mars)	230/500	Dec-25	VA	842.3
Verona Transformer#2 New Circuit Switcher	115	Dec-25	VA	0.5
Princess Anne Sub upgrade TX1	115	Dec-25	VA	0.5
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Dec-25	VA	3.0
Line #183 Rebuild to Resolve EOL and 2021 OW Violations	115	Dec-25	VA	38.0
Line #53 and Line #72 (Chesterfield to Brown Boveri Tap) EOL Partial Rebuild	115	Dec-25	VA	9.8
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Dec-25	VA	1.0
230kV Line Extension to Relieve Waxpool Loop (Nimbus to Farmwell)	230	Dec-25	VA	5.7
Line #2007 (Lynnhaven to Thalia) EOL Rebuild	230	Dec-25	VA	28.7
Brambleton Overdutied Breaker Replacement (SC102,H302, H402, 218302)	230	Dec-25	VA	1.7
Line #2011 Uprate - Cannon Branch to Clifton (Rebuild)	230	Dec-25	VA	31.7
Harrisonburg TX#6 EOL	115	Jan-26	VA	5.2
Line #2209 Uprate Evergreen Mills to Yardley	230	Jan-26	VA	5.0
Decoy Airfield - 230kV Delivery - DEV	230	Feb-26	VA	12.0
Broderick Drive 230kV Delivery - DEV	230	Feb-26	VA	24.5
Twin Creeks Sub 230kV Delivery - DEV	230	Mar-26	VA	20.0
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation - Engineering Assessment	230	Apr-26	VA	42.2
Hornbaker 230kV Delivery - NOVEC (Avanti) (Liberty-Hornbaker-Pioneer)	230	Apr-26	VA	45.0
Northwoods 230kV Delivery - NOVEC	230	Apr-26	VA	15.8
Germannna 230kV Delivery - DEV	230	Apr-26	VA	24.8
Foxbrook Lane 230kV Delivery - REC (AWS Central Louisa - 1st DP)	230	May-26	VA	55.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Alexanders Corner Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Deep Creek Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Deep Creek Tx 2 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Brown Boveri Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Quantico Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Quantico Tx 2 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Partial Line #26 (Buena Vista to Balcony Falls) Rebuild	115	Jun-26	VA	22.2
Relieve Line #219-2066 Load Drop - Loop Trabue 230kV to Midlothian	230	Jun-26	VA	8.5
Line #502 Terminal Upgrade-Loudoun to Mosby	500	Jun-26	VA	6.3
Daves Store 230kV Delivery - DEV	230	Jun-26	VA	36.5
Tunis Tx 1 Replace Ground Switch with Circuit Switcher	115	Jun-26	NC	0.3
Lines #211 and #228 (Chesterfield to Hopewell) partial rebuild	230	Jun-26	VA	12.3
Line #126 (Earleys to Kelford) Partial Rebuild	115	Jun-26	NC	18.8
Cloud 115kV Cap Bank	115	Jun-26	VA	1.5
Line #23 Bell Ave to Suffolk Partial Rebuild	115	Jun-26	VA	39.5
Line #1024 (Chestnut - S Justice Branch) EOL Rebuild	115	Jun-26	NC	5.1
Spartan - New 230kV Substation	230	Jun-26	VA	21.3
Sycolin Creek 230kV Delivery - DEV	230	Jun-26	VA	28.0
Line #2226 (Clover to Easters) Partial Rebuild (DNH)	230	Jun-26	VA	34.0
Line #205 (Locks to Tyler) Partial Rebuild	230	Jun-26	VA	27.0
Jeffress Substation 230 kV Delivery (MEC) - Lakeside DP	230	Jul-26	VA	92.6
Line #2172 Uprate - Brambleton to Evergreen	230	Jul-26	VA	2.3
Line #2213 Uprate - Yardley to Cabin Run	230	Jul-26	VA	1.8
Line #2210 Uprate - Brambleton to Evergreen Mills	230	Jul-26	VA	2.3
Daves Store 230 kV Line Extension (New) (Cut and Extend Line #2161 Gainesville - Wheeler)	230	Aug-26	VA	45.9
Gemini 230 kV Delivery - DEV	230	Aug-26	VA	15.3
Bear Run Sub - Cub Run 230kV Expansion - NOVEC	230	Sep-26	VA	24.5
Install Cap Bank at Lexington Substation	500	Nov-26	VA	5.9
Mint Springs (Jacksonville) 230kV Delivery - NOVEC	230	Nov-26	VA	16.0
Possum Point 2nd 500-230kV TX (Ox Overloads) (PP 500kV - PP230kV)	230/500	Nov-26	VA	23.1
Wishing Star DP -NOVEC	230	Dec-26	VA	10.0
Line #2080 Uprate - Liberty to Railroad DP	230	Dec-26	VA	1.5
Line #2163 Uprate - Vint Hill to Liberty	230	Dec-26	VA	13.0
Line #2187 and #2228 Uprate - Pioneer DP to Liberty	230	Dec-26	VA	11.4

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Occoquan 500-230kV TX (OX violation); Line 2013 Upgrade and Cut in of Line #571 and #237	230/500	Dec-26	VA	84.5
Line #29 Fredericksburg to Aquia Harbor Rebuild	230	Dec-26	VA	59.5
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.3
Line #108 (Boykins-Tunis) EOL Rebuild	115	Dec-26	NC	72.7
Line #584 Terminal Upgrade-Loudoun to Mosby	500	Dec-26	VA	6.4
Line #2056 (Hornertown-Hathaway) EOL Rebuild	230	Dec-26	NC	49.1
City of Franklin P&L DP#4 (Pretlow) - New 115kV Delivery Point	115	Dec-26	VA	2.5
Remington CT 230 kV Terminal Upgrades (Line #2114)	230	Dec-26	VA	2.6
Gainesville 230 kV Terminal Upgrades (Line #2222)	230	Dec-26	VA	9.2
Otterdam Sub - 230kV Delivery (MEC) - Otterdam DP	230	Dec-26	VA	25.0
Bermuda Hundred 230kV Delivery - DEV	230	Dec-26	VA	15.0
Line #260 (Harrisonburg to Grottoes) EOL Rebuild	230	Dec-26	VA	28.0
Line # 2090 (Ladysmith CT to Summit) Rebuild	230	Jan-27	VA	32.0
Line #1001 (Battleboro to Chestnut) EOL Rebuild	115	Jan-27	NC	14.0
Lunar 230kV Delivery - DEV	230	Mar-27	VA	28.0
Youngs Branch - Add 3rd, 4th, 5th TX - DEV (Position #1,3,5)	230	Apr-27	VA	1.2
Mars 2nd 500 -230 kV TX	230/500	May-27	VA	42.2
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Evergreen Mills 230kV Delivery Part B	230	Jun-27	VA	7.7
Pluto 230 kV Delivery - DEV	230	Jun-27	VA	64.5
Terminate Line 583 Doubs - Bismark into Woodside 500kV DOM	500	Jun-27	VA	5.1
Lines #2150 & #2081 Uprates-Golden to Paragon Park	230	Jun-27	VA	3.0
Line #2207 Uprate- Paragon Park to Beco	230	Jun-27	VA	5.3
Line #256 (Ladysmith - St John) Partial Rebuild	230	Jun-27	VA	31.7
Loudoun Capacitor Banks	230/500	Jun-27	VA	90.1
Line #14 (Fudge Hollow to the demarcation point of AEP) EOL	115	Jun-27	VA	30.0
Line #9290 (Ox to Braddock) and Partial Line#2097 Uprate	230	Jun-27	VA	43.5
Line #272 (Dooms to Grottoes) EOL Rebuild	230	Jul-27	VA	34.0
Line #2008 Uprate - Loudoun to Takeoff	230	Aug-27	VA	4.6
Line #265 Uprate - Sully to Takeoff	230	Aug-27	VA	4.6

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Takeoff 230kV Delivery - DEV Transformers	230	Aug-27	VA	4.0
Takeoff Substation 230kV Interconnection for Poland Loop	230	Aug-27	VA	45.9
230kV Line Extension to Relieve Poland Loop (Aviator to Takeoff)	230	Aug-27	VA	29.5
Spring Hill 230kV Delivery - DEV	230	Aug-27	VA	35.0
Edsall 230 kV Delivery - DEV	230	Oct-27	VA	23.2
Mountain Run new 230kV substation (Named Cirrus) and partial conversion of lines #2 and #70 to 230kV; Convert lines #2 and #70 to 230kV and connect to Line #2199	230	Nov-27	VA	60.0
Line # 2054 (Charlottesville to Hollymead) Rebuild	230	Dec-27	VA	71.1
Locks Substation 230/115 kV Transformer Upgrade	115/230	Dec-27	VA	7.1
Line # 2135 (HollyMeade to Gordonsville) Rebuild	230	Dec-27	VA	36.8
Line #58 (Skiffes to Yorktown) EOL Partial Rebuild	115	Dec-27	VA	6.0
Line #209 and #58 (Skiffes to Yorktown) EOL Partial Rebuild	115/230	Dec-27	VA	13.5
Terminate New Nextera 500kV Line from Woodside into Goose Creek Sub DOM	500	Dec-27	VA	30.5
Line #2101 Uprate - Bristers to Bristers Junction	230	Dec-27	VA	23.0
Sloan Drive - 230kV Delivery - DEV	230	Dec-27	VA	30.0
5-2 North Line Extension - Aspen to Golden	230/500	Dec-27	VA	623.0
Line #204 and #220 Partial Rebuild EOL	230	Dec-27	VA	5.4
Nokesville to Hornbaker 230 kV Line (new)	230	Dec-27	VA	139.0
500 kV line extension - Aspen to Doubs	230/500	Dec-27	VA	74.0
Apollo 230kV Delivery - DEV	230	Mar-28	VA	28.0
Partial Line #83 EOL Rebuild	115	Mar-28	VA	23.0
Atlas 230 kV Delivery - DEV	230	Apr-28	VA	15.4
Line #557 (Chickahominy to Elmont) EOL Rebuild	500	Jun-28	VA	58.2
5-2 Connector - Mars to Golden	230/500	Jun-28	VA	342.9
Starlight 230kV Delivery - DEV	230	Jun-28	VA	28.0
Lucky Hill Substation - paused	230	Jun-28	VA	7.5
Barrister Sub 230kV Delivery - DEV (CPR changed to Engineering)	230	Jun-28	VA	24.0
Lines #2150 & #2081 Uprates-Golden to Sterling Park	230	Sep-28	VA	8.0
Lines #2194 & #9231 Uprates-Davis Drive to Sterling Park	230	Sep-28	VA	5.5

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Nimbus 230kV Delivery - Add 3rd and 4th TX	230	Oct-28	VA	1.1
Lines #233 and 291 (Dooms to Charlottesville) Rebuild	230	Dec-28	VA	112.4
Weyers Cave Substation - New 2nd Transformer	115	Dec-28	VA	0.9
Line #246 Earleys to Suffolk EOL Rebuild	230	Dec-28	VA-NC	150.0
Convert Line #29 Fredericksburg to Possum Point to 230 kV	230	Jan-29	VA	56.7
Line #29 and #252 (Possum Point to Aquia Harbor) Rebuild	230	Jan-29	VA	38.0
Line #10 (Goshen to Craigsville) EOL Partial Rebuild	115	Mar-29	VA	29.6
Fentress Sub - Add 2nd TX	230	May-29	VA	0.4
Vint Hill 500-230 kV Expansion	230/500	Jun-29	VA	115.0
500/230kV Morrisville-Wishing Star Upgrades	230/500	Jun-30	VA	852.9
New Nextera 500 kV Line from Woodside to Goose Creek Sub (DOM Scope)	500	Sep-30	VA	15.6
Replace Overdutied Breakers _ 2022 Reliability Open Window #3	230/500	Oct-31	VA	66.3



**Virginia Electric and Power
Company's Report of Its
2024 Integrated Resource Plan**

**Before the Virginia State
Corporation Commission and
North Carolina Utilities
Commission**

**Case No. PUR-2024-00184
Docket No. E-100, Sub 204**

Filed: October 15, 2024

Appendix 2C-1: List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Winters Branch - Add 4th TX - DEV (Position #4)	230	Aug-24	VA	0.3
Pearsons 230kV Switch Replacements EOL	230	Aug-24	VA	0.5
Altair 230kV Delivery - NOVEC (Microsoft Leesburg) (Belmont-Altair-Brambleton)	230	Sep-24	VA	51.9
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Sep-24	VA	151.0
Youngs Branch - Add 2nd TX - DEV	230	Sep-24	VA	0.8
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Cemetery Road Sub - 115kV Delivery - DEV	115	Oct-24	VA	5.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Oct-24	VA	13.9
Clifton Forge TX#2 EOL	138/230	Nov-24	VA	3.0
Line #2008 Uprate - Takeoff to Lincoln Park	230	Nov-24	VA	4.5
Line #2008 Uprate - Takeoff to Walney	230	Nov-24	VA	2.0
Gretna 69kV Delivery - Add 2nd TX - DEV	69	Nov-24	VA	0.6
Line #2008 Uprate - Cub Run to Walney	230	Nov-24	VA	2.0
Line #2242 Uprate - Dulles to Lincoln Park	230	Nov-24	VA	6.0
230kV Line Extension Cannon Branch to Winters Branch	230	Dec-24	VA	22.0
Trappe Rock 230kV Delivery - NOVEC	230	Dec-24	VA	16.2
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Dec-24	VA	0.8
Farmville 230-115kV Transformer #5 EOL Replacement	115/230	Dec-24	VA	6.4
NIVO - Bus Expansion	230	Dec-24	VA	12.0
Magruder Sub - Upgrade 115/34.5kV TX#1 - DEV	115	Dec-24	VA	1.0
Northstar 230kV Delivery - NOVEC	230	Dec-24	VA	10.0
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild - 1.7 mile Double Circuit Sections with Line #2056 (Hornertown-Hathaway)	115	Dec-24	NC	3.4
Metcalf Sub 115kV Delivery - TX #1 Upgrade - DEV	115	Dec-24	VA	0.6
Harrisonburg Transformer#1 Upgrade	115	Dec-24	VA	0.3
NIT Industrial - New 230kV Delivery Point (DEV)	230	Dec-24	VA	5.0
Line #2010 Underground Relocation	230	Dec-24	VA	40.0
Line #100 (Locks to Harrowgate) Partial Rebuild	115	Dec-24	VA	9.1
Bishop Substation -115 kV Delivery (MEC) - Ridge DP	115	Mar-25	VA	15.0
Jeffress Sub - 115 kV Delivery (MEC) - Lakeside DP	115	Feb-25	VA	15.5

Appendix 2C-1: List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Nimbus 230kV Delivery - DEV (Beaumeade-Nimbus-Buttermilk)	230	Apr-25	VA	12.0
Line #141 (Balcony Falls to Skimmer) & Line#28 (Balcony Falls to Cushaw) EOL and Balcony Falls Substation Rebuild	115	May-25	VA	55.0
DTC 230kV Delivery - DEV (Extension of Line #2143 (Beaumeade-BECO) to DTC)	230	Jun-25	VA	60.3
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2186 Uprate - Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2218 Uprate-Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Rixlew 230 kV Delivery - NOVEC	230	Jun-25	VA	10.0
Lost City - New 230 kV Delivery - DEV	230	Jul-25	VA	10.2
Line #105 (Tarboro-Parmelee) EOL Rebuild	115	Jul-25	NC	26.0
Partial Line#5 Retirement (Fork Union to Cunningham DP)-line 1049 retirement	115	Aug-25	VA	5.5
Interconnection 230kV Delivery - DEV (Beaumeade-Interconnection-Nimbus)	230	Sep-25	VA	32.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Oct-25	VA	15.3
Ocean Court 230kV Delivery - DEV	230	Oct-25	VA	12.7
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.2
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Stratus 230kV Delivery - DEV - (CPR changed to Engineering)	230	Dec-25	VA	24.0
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Dec-25	VA	1.0
Hornbaker 230kV Delivery - NOVEC (Avanti) (Liberty-Hornbaker-Pioneer)	230	Apr-26	VA	45.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Bear Run Sub - Cub Run 230kV Expansion - NOVEC	230	Sep-26	VA	24.5
Wishing Star DP -NOVEC	230	Dec-26	VA	10.0
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.3
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Line #2008 Uprate - Loudoun to Takeoff	230	Aug-27	VA	4.6
Partial Line #83 EOL Rebuild	115	Mar-28	VA	23.0

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Winters Branch - Add 4th TX - DEV (Position #4)	230	Aug-24	VA	0.3
Pearsons 230kV Switch Replacements EOL	230	Aug-24	VA	0.5
Altair 230kV Delivery - NOVEC (Microsoft Leesburg) (Belmont-Altair-Brambleton)	230	Sep-24	VA	51.9
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Sep-24	VA	151.0
Youngs Branch - Add 2nd TX - DEV	230	Sep-24	VA	0.8
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Cemetery Road Sub - 115kV Delivery - DEV	115	Oct-24	VA	5.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Oct-24	VA	13.9
Clifton Forge TX#2 EOL	138/230	Nov-24	VA	3.0
Line #2008 Uprate - Takeoff to Lincoln Park	230	Nov-24	VA	4.5
Line #2008 Uprate - Takeoff to Walney	230	Nov-24	VA	2.0
Gretna 69kV Delivery - Add 2nd TX - DEV	69	Nov-24	VA	0.6
Line #2008 Uprate - Cub Run to Walney	230	Nov-24	VA	2.0
Line #2242 Uprate - Dulles to Lincoln Park	230	Nov-24	VA	6.0
230kV Line Extension Cannon Branch to Winters Branch	230	Dec-24	VA	22.0
Trappe Rock 230kV Delivery - NOVEC	230	Dec-24	VA	16.2
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Dec-24	VA	0.8
Farmville 230-115kV Transformer #5 EOL Replacement	115/230	Dec-24	VA	6.4
NIVO - Bus Expansion	230	Dec-24	VA	12.0
Magruder Sub - Upgrade 115/34.5kV TX#1 - DEV	115	Dec-24	VA	1.0
Northstar 230kV Delivery - NOVEC	230	Dec-24	VA	10.0
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild - 1.7 mile Double Circuit Sections with Line #2056 (Hornertown-Hathaway)	115	Dec-24	NC	3.4
Metcalf Sub 115kV Delivery - TX #1 Upgrade - DEV	115	Dec-24	VA	0.6
Harrisonburg Transformer#1 Upgrade	115	Dec-24	VA	0.3
NIT Industrial - New 230kV Delivery Point (DEV)	230	Dec-24	VA	5.0
Line #2010 Underground Relocation	230	Dec-24	VA	40.0
Line #100 (Locks to Harrowgate) Partial Rebuild	115	Dec-24	VA	9.1
Bishop Substation -115 kV Delivery (MEC) - Ridge DP	115	Mar-25	VA	15.0
Jeffress Sub - 115 kV Delivery (MEC) - Lakeside DP	115	Feb-25	VA	15.5

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch - Wakeman)	230	Mar-25	VA	3.9
EPG - Add 2nd and 3rd TX - DEV	230	Mar-25	VA	6.1
Nimbus 230kV Delivery - DEV (Beaumeade-Nimbus-Buttermilk)	230	Apr-25	VA	12.0
Line #141 (Balcony Falls to Skimmer) & Line#28 (Balcony Falls to Cushaw) EOL and Balcony Falls Substation Rebuild	115	May-25	VA	55.0
Davis Drive - 230kV Ring Bus Expansion - Line Extension W&OD Trail to Sub	230	Jun-25	VA	15.0
Clifton - Replace Overdutied L282 Breaker	230	Jun-25	VA	0.5
Install 115kV breaker at Stuarts Draft station	115	Jun-25	VA	5.0
Cumulus 230kV Delivery - Add 5th TX - DEV	230	Jun-25	VA	0.5
DTC 230kV Delivery - DEV (Extension of Line #2143 (Beaumeade-BECO) to DTC)	230	Jun-25	VA	60.3
Sherwood Transformer#2 Upgrade	115	Jun-25	VA	0.4
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2186 Uprate - Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Jun-25	VA	3.8
Line #2214 Uprate - Buttermilk to Roundtable	230	Jun-25	VA	4.8
Line #2218 Uprate-Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Line #2223 Uprate-Roundtable to Lockridge	230	Jun-25	VA	2.6
Rixlew 230 kV Delivery - NOVEC	230	Jun-25	VA	10.0
Line #249 (Carson to Locks) Rebuild and Energize TX #1	230	Jun-25	VA	25.6
Line #2151 Uprate - Railroad DP to Gainesville	230	Jun-25	VA	6.1
King and Queen 230kV Delivery - DEV	230	Jul-25	VA	1.9
Lost City - New 230 kV Delivery - DEV	230	Jul-25	VA	10.2
Varina SUB - add new TX (TX #2) - DEV	230	Jul-25	VA	0.5
Line #105 (Tarboro-Parmeale) EOL Rebuild	115	Jul-25	NC	26.0
Evans Creek Sub - Roanoke DP - 230kV Delivery-DEV_New 230kV Line from Tunstall to Evans Creek and Evans Creek to Raines	230	Aug-25	VA	30.0

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Raines Sub - Interstate DP - 230kV Delivery-DEV-New 230kV Line from Tunstall to Raines -	230	Aug-25	VA	20.0
Tunstall Sub - Hillcrest DP - 230kV Delivery-DEV-New Unity 500/230kV Sub - Two New 230kV Lines from Unity to Tunstall	230/500	Aug-25	VA	140.0
Partial Line#5 Retirement (Fork Union to Cunningham DP)-line 1049 retirement	115	Aug-25	VA	5.5
Trident 230 kV Delivery - NOVEC (ARC West) (Gainesville-Trident-Wheeler)	230	Sep-25	VA	15.8
Interconnection 230kV Delivery - DEV (Beaumeade-Interconnection-Nimbus)	230	Sep-25	VA	32.0
Park Center 230kV Delivery - DEV	230	Sep-25	VA	10.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Oct-25	VA	15.3
Ocean Court 230kV Delivery - DEV	230	Oct-25	VA	12.7
Prentice Drive 230kV Delivery - DEV (CPR changed to Engineering)	230	Oct-25	VA	20.0
Southall (North Louisa (REB)) 230kV Delivery (Amazon AZ) - ODEC - Engineering	230	Nov-25	VA	55.0
Line #77 (Carolina-Roanoke Rapids Hydro) EOL Rebuild	115	Nov-25	VA	7.4
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.2
Install 2nd 115kV 33.67MVar Cap bank at Harrisonburg	115	Dec-25	VA	1.0
Walnut Creek 115kV switching station	115	Dec-25	VA	23.7
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Stratus 230kV Delivery - DEV - (CPR changed to Engineering)	230	Dec-25	VA	24.0
Brickyard 230kV Delivery - DEV	230	Dec-25	VA	6.6
Buttermilk 230kV Delivery - Add 3rd and 4th TX	230	Dec-25	VA	1.0
Butler Farm Sub - 230kV Delivery-DEV- Bailey DP - New Finneywood 500/230kV Sub a new 230kV Line (Butler Farm - Finneywood) and a new 230kV Line (Butler Farm - Clover)	230/500	Dec-25	VA	220.0
Line #2019 (Greenwich to Thalia) EOL Partial Rebuild	230	Dec-25	VA	14.3
Line #293 (Staunton to Valley) & Partial Line #83 EOL	230	Dec-25	VA	44.8
Line #202 - Clark to Idylwood Uprate	230	Dec-25	VA	8.0

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Line #2104 (Cranes Corner to Stafford) partial uprate	230	Dec-25	VA	28.3
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
500kV / 230kV Line Extension - Southern (Wishing Star to Mars)	230/500	Dec-25	VA	842.3
Verona Transformer#2 New Circuit Switcher	115	Dec-25	VA	0.5
Princess Anne Sub upgrade TX1	115	Dec-25	VA	0.5
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Dec-25	VA	3.0
Line #183 Rebuild to Resolve EOL and 2021 OW Violations	115	Dec-25	VA	38.0
Line #53 and Line #72 (Chesterfield to Brown Boveri Tap) EOL Partial Rebuild	115	Dec-25	VA	9.8
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Dec-25	VA	1.0
230kV Line Extension to Relieve Waxpool Loop (Nimbus to Farmwell)	230	Dec-25	VA	5.7
Line #2007 (Lynnhaven to Thalia) EOL Rebuild	230	Dec-25	VA	28.7
Brambleton Overduty Breaker Replacement (SC102, H302, H402, 218302)	230	Dec-25	VA	1.7
Line #2011 Uprate - Cannon Branch to Clifton (Rebuild)	230	Dec-25	VA	31.7
Harrisonburg TX#6 EOL	115	Jan-26	VA	5.2
Line #2209 Uprate Evergreen Mills to Yardley	230	Jan-26	VA	5.0
Decoy Airfield - 230kV Delivery - DEV	230	Feb-26	VA	12.0
Broderick Drive 230kV Delivery - DEV	230	Feb-26	VA	24.5
Twin Creeks Sub 230kV Delivery - DEV	230	Mar-26	VA	20.0
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation - Engineering Assessment	230	Apr-26	VA	42.2
Hornbaker 230kV Delivery - NOVEC (Avanti) (Liberty-Hornbaker-Pioneer)	230	Apr-26	VA	45.0
Northwoods 230kV Delivery - NOVEC	230	Apr-26	VA	15.8
Germanna 230kV Delivery - DEV	230	Apr-26	VA	24.8
Foxbrook Lane 230kV Delivery - REC (AWS Central Louisa - 1st DP)	230	May-26	VA	55.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Alexanders Corner Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Deep Creek Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Deep Creek Tx 2 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Brown Boveri Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Quantico Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Quantico Tx 2 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Partial Line #26 (Buena Vista to Balcony Falls) Rebuild	115	Jun-26	VA	22.2
Relieve Line #219-2066 Load Drop - Loop Trabue 230kV to Midlothian	230	Jun-26	VA	8.5
Line #502 Terminal Upgrade-Loudoun to Mosby	500	Jun-26	VA	6.3
Daves Store 230kV Delivery - DEV	230	Jun-26	VA	36.5
Tunis Tx 1 Replace Ground Switch with Circuit Switcher	115	Jun-26	NC	0.3
Lines #211 and #228 (Chesterfield to Hopewell) partial rebuild	230	Jun-26	VA	12.3
Line #126 (Earleys to Kelford) Partial Rebuild	115	Jun-26	NC	18.8
Cloud 115kV Cap Bank	115	Jun-26	VA	1.5
Line #23 Bell Ave to Suffolk Partial Rebuild	115	Jun-26	VA	39.5
Line #1024 (Chestnut - S Justice Branch) EOL Rebuild	115	Jun-26	NC	5.1
Spartan - New 230kV Substation	230	Jun-26	VA	21.3
Sycolin Creek 230kV Delivery - DEV	230	Jun-26	VA	28.0
Line #2226 (Clover to Easters) Partial Rebuild (DNH)	230	Jun-26	VA	34.0
Line #205 (Locks to Tyler) Partial Rebuild	230	Jun-26	VA	27.0
Jeffress Substation 230 kV Delivery (MEC) - Lakeside DP	230	Jul-26	VA	92.6
Line #2172 Uprate - Brambleton to Evergreen	230	Jul-26	VA	2.3
Line #2213 Uprate - Yardley to Cabin Run	230	Jul-26	VA	1.8
Line #2210 Uprate - Brambleton to Evergreen Mills	230	Jul-26	VA	2.3
Daves Store 230 kV Line Extension (New) (Cut and Extend Line #2161 Gainesville - Wheeler)	230	Aug-26	VA	45.9
Gemini 230 kV Delivery - DEV	230	Aug-26	VA	15.3
Bear Run Sub - Cub Run 230kV Expansion - NOVEC	230	Sep-26	VA	24.5
Install Cap Bank at Lexington Substation	500	Nov-26	VA	5.9
Mint Springs (Jacksonville) 230kV Delivery - NOVEC	230	Nov-26	VA	16.0
Possum Point 2nd 500-230kV TX (Ox Overloads) (PP 500kV - PP230kV)	230/500	Nov-26	VA	23.1
Wishing Star DP -NOVEC	230	Dec-26	VA	10.0
Line #2080 Uprate - Liberty to Railroad DP	230	Dec-26	VA	1.5
Line #2163 Uprate - Vint Hill to Liberty	230	Dec-26	VA	13.0
Line #2187 and #2228 Uprate - Pioneer DP to Liberty	230	Dec-26	VA	11.4

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Occoquan 500-230kV TX (OX violation); Line 2013 Upgrade and Cut in of Line #571 and #237	230/500	Dec-26	VA	84.5
Line #29 Fredericksburg to Aquia Harbor Rebuild	230	Dec-26	VA	59.5
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.3
Line #108 (Boykins-Tunis) EOL Rebuild	115	Dec-26	NC	72.7
Line #584 Terminal Upgrade-Loudoun to Mosby	500	Dec-26	VA	6.4
Line #2056 (Hornertown-Hathaway) EOL Rebuild	230	Dec-26	NC	49.1
City of Franklin P&L DP#4 (Pretlow) - New 115kV Delivery Point	115	Dec-26	VA	2.5
Remington CT 230 kV Terminal Upgrades (Line #2114)	230	Dec-26	VA	2.6
Gainesville 230 kV Terminal Upgrades (Line #2222)	230	Dec-26	VA	9.2
Otterdam Sub - 230kV Delivery (MEC) - Otterdam DP	230	Dec-26	VA	25.0
Bermuda Hundred 230kV Delivery - DEV	230	Dec-26	VA	15.0
Line #260 (Harrisonburg to Grottoes) EOL Rebuild	230	Dec-26	VA	28.0
Line # 2090 (Ladysmith CT to Summit) Rebuild	230	Jan-27	VA	32.0
Line #1001 (Battleboro to Chestnut) EOL Rebuild	115	Jan-27	NC	14.0
Lunar 230kV Delivery - DEV	230	Mar-27	VA	28.0
Youngs Branch - Add 3rd, 4th, 5th TX - DEV (Position #1,3,5)	230	Apr-27	VA	1.2
Mars 2nd 500 -230 kV TX	230/500	May-27	VA	42.2
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Evergreen Mills 230kV Delivery Part B	230	Jun-27	VA	7.7
Pluto 230 kV Delivery - DEV	230	Jun-27	VA	64.5
Terminate Line 583 Doubs - Bismark into Woodside 500kV DOM	500	Jun-27	VA	5.1
Lines #2150 & #2081 Uprates-Golden to Paragon Park	230	Jun-27	VA	3.0
Line #2207 Uprate- Paragon Park to Beco	230	Jun-27	VA	5.3
Line #256 (Ladysmith - St John) Partial Rebuild	230	Jun-27	VA	31.7
Loudoun Capacitor Banks	230/500	Jun-27	VA	90.1
Line #14 (Fudge Hollow to the demarcation point of AEP) EOL	115	Jun-27	VA	30.0
Line #9290 (Ox to Braddock) and Partial Line#2097 Uprate	230	Jun-27	VA	43.5
Line #272 (Dooms to Grottoes) EOL Rebuild	230	Jul-27	VA	34.0
Line #2008 Uprate - Loudoun to Takeoff	230	Aug-27	VA	4.6
Line #265 Uprate - Sully to Takeoff	230	Aug-27	VA	4.6

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Takeoff 230kV Delivery - DEV Transformers	230	Aug-27	VA	4.0
Takeoff Substation 230kV Interconnection for Poland Loop	230	Aug-27	VA	45.9
230kV Line Extension to Relieve Poland Loop (Aviator to Takeoff)	230	Aug-27	VA	29.5
Spring Hill 230kV Delivery - DEV	230	Aug-27	VA	35.0
Edsall 230 kV Delivery - DEV	230	Oct-27	VA	23.2
Mountain Run new 230kV substation (Named Cirrus) and partial conversion of lines #2 and #70 to 230kV; Convert lines #2 and #70 to 230kV and connect to Line #2199	230	Nov-27	VA	60.0
Line # 2054 (Charlottesville to Hollymead) Rebuild	230	Dec-27	VA	71.1
Locks Substation 230/115 kV Transformer Upgrade	115/230	Dec-27	VA	7.1
Line # 2135 (HollyMeade to Gordonsville) Rebuild	230	Dec-27	VA	36.8
Line #58 (Skiffes to Yorktown) EOL Partial Rebuild	115	Dec-27	VA	6.0
Line #209 and #58 (Skiffes to Yorktown) EOL Partial Rebuild	115/230	Dec-27	VA	13.5
Terminate New Nextera 500kV Line from Woodside into Goose Creek Sub DOM	500	Dec-27	VA	30.5
Line #2101 Uprate - Bristers to Bristers Junction	230	Dec-27	VA	23.0
Sloan Drive - 230kV Delivery - DEV	230	Dec-27	VA	30.0
5-2 North Line Extension - Aspen to Golden	230/500	Dec-27	VA	623.0
Line #204 and #220 Partial Rebuild EOL	230	Dec-27	VA	5.4
Nokesville to Hornbaker 230 kV Line (new)	230	Dec-27	VA	139.0
500 kV line extension - Aspen to Doubs	230/500	Dec-27	VA	74.0
Apollo 230kV Delivery - DEV	230	Mar-28	VA	28.0
Partial Line #83 EOL Rebuild	115	Mar-28	VA	23.0
Atlas 230 kV Delivery - DEV	230	Apr-28	VA	15.4
Line #557 (Chickahominy to Elmont) EOL Rebuild	500	Jun-28	VA	58.2
5-2 Connector - Mars to Golden	230/500	Jun-28	VA	342.9
Starlight 230kV Delivery - DEV	230	Jun-28	VA	28.0
Lucky Hill Substation - paused	230	Jun-28	VA	7.5
Barrister Sub 230kV Delivery - DEV (CPR changed to Engineering)	230	Jun-28	VA	24.0
Lines #2150 & #2081 Uprates-Golden to Sterling Park	230	Sep-28	VA	8.0
Lines #2194 & #9231 Uprates-Davis Drive to Sterling Park	230	Sep-28	VA	5.5

Appendix 2C-2: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates (\$M)
Nimbus 230kV Delivery - Add 3rd and 4th TX	230	Oct-28	VA	1.1
Lines #233 and 291 (Dooms to Charlottesville) Rebuild	230	Dec-28	VA	112.4
Weyers Cave Substation - New 2nd Transformer	115	Dec-28	VA	0.9
Line #246 Earleys to Suffolk EOL Rebuild	230	Dec-28	VA-NC	150.0
Convert Line #29 Fredericksburg to Possum Point to 230 kV	230	Jan-29	VA	56.7
Line #29 and #252 (Possum Point to Aquia Harbor) Rebuild	230	Jan-29	VA	38.0
Line #10 (Goshen to Craigsville) EOL Partial Rebuild	115	Mar-29	VA	29.6
Fentress Sub - Add 2nd TX	230	May-29	VA	0.4
Vint Hill 500-230 kV Expansion	230/500	Jun-29	VA	115.0
500/230kV Morrisville-Wishing Star Upgrades	230/500	Jun-30	VA	852.9
New Nextera 500 kV Line from Woodside to Goose Creek Sub (DOM Scope)	500	Sep-30	VA	15.6
Replace Overdutied Breakers 2022 Reliability Open Window #3	230/500	Oct-31	VA	66.3

DUKE 2023 CAROLINAS RESOURCE PLAN*

Table L-2: DEC and DEP Transmission Under Construction or Approved for Construction¹

DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MW)	New/Upgrade
DEC	2024	Aquidale PV (50 MW)		100		New
DEC	2024	Blackburn PV (60.1 MW)		100		New
DEC	2024	Brookfield PV (50 MW)		100		New
DEC	2024	Hornet PV (76 MW)		100		New
DEC	2024	BM Tap	GE Aircraft Tie	100	200	Upgrade
DEC	2024	Mebane Tie	Piedmont EMC 10	100	143	New
DEC	2024	Newberry PV (74.5 MW)		100		New
DEC	2024	Oakboro PV (40 MW)		100		New
DEC	2024	West River PV (40 MW)		100		New
DEC	2024	Wilkes 230/100 kV Transformer		230/100	448	New
DEC	2024	Woodruff Tie	BMW	100		New
DEC	2025	Allen 230/100 kV Transformer (2)		230/100	448	Upgrade
DEC	2025	Citfide	Peach Valley Tie	100		Upgrade
DEC	2025	Hanging Springs PV (55 MW)		100		New
DEC	2025	Hodges Tie	Coronaca Tie	100	450	Upgrade
DEC	2025	Lee	Shady Grove (Lee Lines)	100	368	Upgrade
DEC	2025	Newberry Main	DESC Saluda	115	278	Upgrade
DEC	2025	North Greenville 230/100 kV Transformer		230/100	448	Upgrade
DEC	2026	Boyd Switching Station		230		New
DEC	2026	Bush River Tie	Laurens Tie	100	368	Upgrade
DEC	2026	Croft Tie	Coronaca Tie	100	404	New
DEC	2026	Hass Creek Switching Station		230		New
DEC	2026	Hilltop Tie	Shelby Tie	100		Upgrade
DEC	2026	Lee	Shady Grove (Piedmont Lines)	100	368	Upgrade
DEC	2026	Lyle Creek Switching Station		100		New
DEC	2026	North Greensboro Tie	Greensboro Main (Page)	100	363	Upgrade
DEC	2026	North Greensboro Tie	Greensboro Main (Gulfport)	100	368	Upgrade
DEC	2026	Oakvale Tie	East Greenville	100		Upgrade
DEC	2026	Statesville Tie	Parth Road	100		New
DEC	2026	Wylie	Indianland Rel	100		New
DEC	2026	Wylie Hydro	Woodlawn Tie	100	240	Upgrade
DEC	2027	Lancaster Main	Monroe Main	100	242	Upgrade
DEC	2028	Dorin School Road	New Customer	230		New
DEC	2028	Harrisburg Tie	Amity	100		Upgrade
DEC	2028	Lakewood Tie	Woodlawn Tie	100		Upgrade
DEC	2028	Lee CC	Lee Steam	100	454	New
DEC	2028	Mebane Tie	Piedmont Garden Tie	100		Upgrade
DEC	2028	Oak Hollow Switching Station		100		New
DEC	2028	Shelby Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Concord Main	Wincoff Tie	100		Upgrade
DEC	2029	Concord Main	Harrisburg Tie	100		Upgrade
DEC	2029	Harrisburg Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Hodges 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Newport Tie	Morning Star Tie	230	421	New

¹ Table L-2 lists projects 100 kV and above pursuant to Rule RS-60(a), that are under construction or approved by Duke Energy for construction.

Carolinas Resource Plan.

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*Summary of selected screenshots, compiled by counsel for GIPL and Southface.



Appendix L | Transmission System Planning and Grid Transformation

DEC/DEF	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2028	Tiger Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2028	Wildcat Tie	Westport	100		Upgrade
DEC	2030	Dan River	N Greensboro	100	242'	Upgrade
DEC	2030	Lawson's Fork	W Spartanburg	100		Upgrade
DEC	2030	North Greenville	Marietta	100	454	Upgrade
DEC	2030	Rossbach Triangle	Ellis Rd	100		Upgrade
DEC	2030	Shelby Tie	Citrus	100		Upgrade
DEC	2031	Marshall Rd	Lookout Tie	100		New
DEC	2031	McGuire	Marshall	230		Upgrade
DEC	2032	Morning Star 230/100 kV Transformer (3)		230/100	448	Upgrade
DEC	2033	Dan River	Sadler (Wolf Creek)	100	242'	Upgrade
DEC	2033	Dan River	Sadler (Friedsike)	100	242'	Upgrade
DEC	2034	Wincoff Tie	Conley	100	484	Upgrade
DEF	2023	Havlock 230/115 kV Transformers		230/115	336	Upgrade
DEF	2023	Pig Basket Creek PV (80 MW)		230		New
DEF	2023	Porters Neck Tap	Porters Neck	230	442	New
DEF	2023	Waterlee 115/100 kV Transformers (2)		115/100	336	Upgrade
DEF	2024	Camden	Camden Dupont	115	313	Upgrade
DEF	2024	Lottins Crossroads PV (75 MW)		230		New
DEF	2025	Arden Tap	Arden	115	280	New
DEF	2025	Carthage 230/115 kV Transformer Substation		230/115	336	New
DEF	2025	Crofton	Enka	230	644	New
DEF	2025	Weatherston	Marion	115	313	Upgrade
DEF	2026	Camden Junction	DPC Waterlee	115	313	Upgrade
DEF	2026	Cape Fear	West End	230	1195	Upgrade
DEF	2026	Castle Hayne	Folkstone	115	296	Upgrade
DEF	2026	Erwin	Fayetteville East	230	1195	Upgrade
DEF	2026	Fayetteville	Fayetteville Dupont (4.9 miles)	115	313	Upgrade
DEF	2026	Holy Ridge North 115 kV Switching Station	JOEMC Folkstone POD	115	296	New
DEF	2026	Kingsree West PV (74.9 MW)		115		New
DEF	2026	Maiden	Pembroke	115	313	Upgrade
DEF	2026	Robinson	Rockingham	230	1195	Upgrade
DEF	2026	Sunrise	DESC Eastover	115	270	Upgrade
DEF	2026	Weatherston	LRMC West Lumberton	115	313	Upgrade
DEF	2027	Robinson	Rockingham	115	310	Upgrade
DEF	2028	Delco	Island Industrial	115	221	Upgrade
DEF	2028	Durham	Brier Creek	230	1195	Upgrade
DEF	2029	Cape Fear	Monroe	115	201	Upgrade

Note 1: The MVA Capacity represents the capability for one circuit of the double circuit line

Table L-7: Proposed Red Zone Expansion Plan (RZEP 2.0) Upgrades

Project	Owner	Project Description	Cost Estimate ^{1,2}	Potential In-Service Date
Broadway B/W 100 kV (Behon Tie- W.S. Lee Combined Cycle)	DEC	Rebuild	\$19,749,000	May 2028
Bush River 115/100 kV Transformers	DEC	Upgrade	\$8,523,000	May 2028
Champion B/W 100 kV (Bush River- New Berry PV)	DEC	Rebuild	\$29,114,000	May 2028
Clayton Industrial - Selma 115 kV	DEP	Rebuild	\$27,741,000	Sep 2028
Lilesville-Oakboro 230 kV Black ³	DEP	Rebuild	\$54,470,000	Dec 2029
Lilesville-Oakboro 230 kV White ³	DEP	Rebuild	\$54,470,000	Dec 2029

Note 1 : Class 5 Cost Estimate from the DEC 2022 DHSIS Phase 2 Study Report.⁴²

Note 2 : Class 5 Cost Estimate from the DEP 2022 DHSIS Phase 1 Study Report.⁴³

Note 3 : Cost Estimate includes upgrading the entire tie-line but excludes any upgrades to be identified as needed in the DEC Oakboro 230 kV substation

Table L-8: Proposed Red Zone Expansion Plan (RZEP 1.0) Project Status

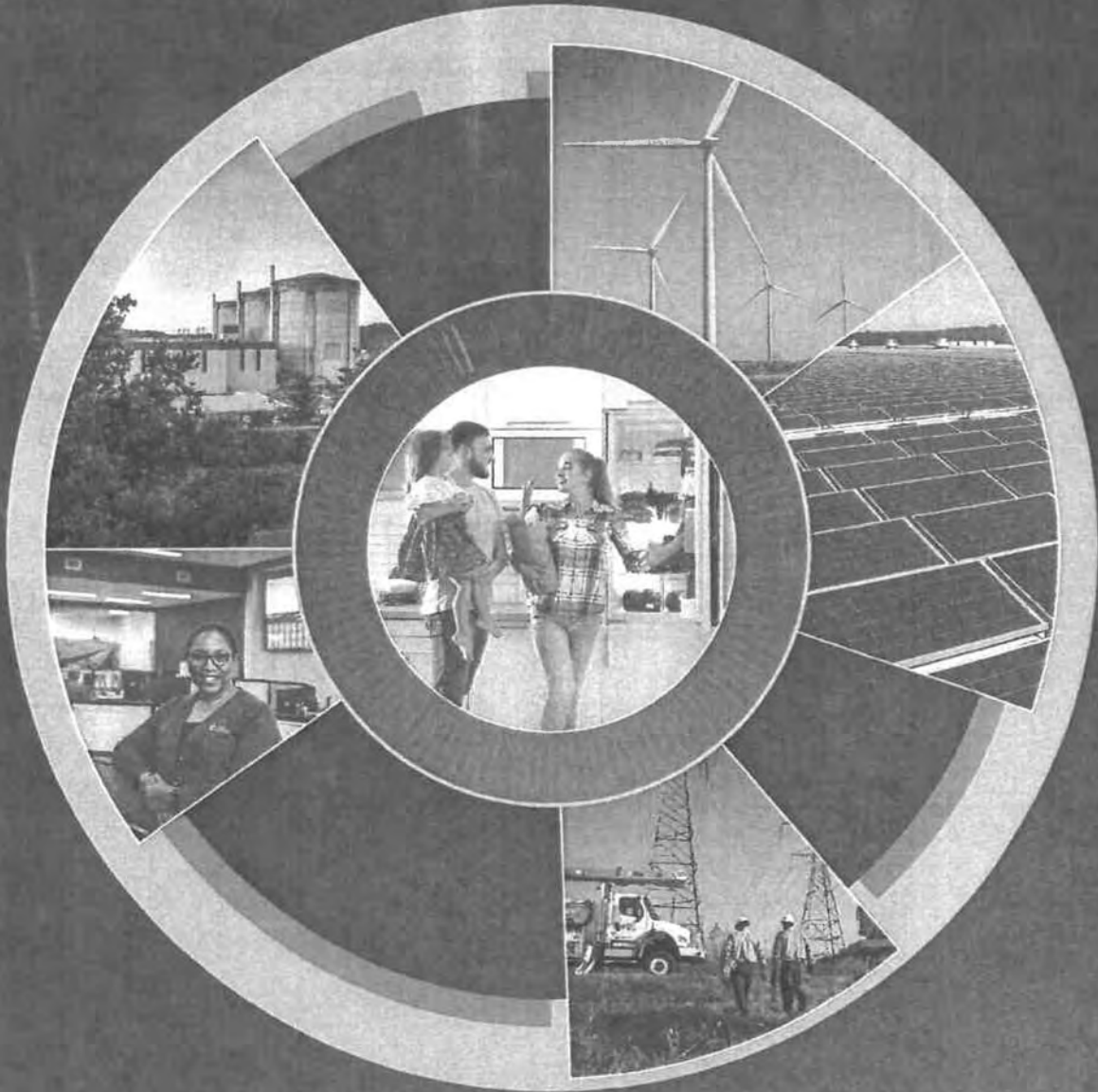
Project	Owner	Project Description	Cost Estimate ¹	Planned In-Service Date
Lee 100 kV (Lee-Shady Grove)	DEC	Rebuild	\$39,660,000	Aug 2025
Piedmont 100 kV (Lee-Shady Grove)	DEC	Rebuild	\$40,080,000	Aug 2026
Newberry 115 kV (Bush River-DESC)	DEC	Rebuild	\$34,583,000	Apr 2025
Clinton 100 kV (Bush River-Laurana)	DEC	Rebuild	\$66,091,000	Oct 2026
Cape Fear Plant-West End 230 kV Line	DEP	Rebuild	\$83,033,000	Jun 2026
Erwin-Fayetteville East 230 kV Line	DEP	Rebuild	\$99,826,000	Jun 2026
Erwin-Fayetteville 115 kV Line	DEP	Rebuild	\$24,063,000	Jun 2025
Fayetteville-Fayetteville Dupont 115 kV Line - 3.2-mile section	DEP	Rebuild	\$15,574,000	Dec 2024
Milburnie 230 kV Substation	DEP	Redundant Bus Protection	\$5,206,000	Apr 2026
Weather Spoon-Marion 115 kV Line	DEP	Rebuild	\$21,167,000	Dec 2025
Camden Junction-DPC Wateree 115 kV Line	DEP	Rebuild	\$15,909,000	Dec 2026
Robinson Plant-Rockingham 115 kV Line	DEP	Rebuild	\$42,293,000	Jun 2027
Robinson Plant-Rockingham 230 kV Line	DEP	Rebuild	\$49,020,000	Jun 2026
Fayetteville-Fayetteville Dupont 115 kV Line - 4.9-mile section	DEP	Rebuild	\$15,574,000	Apr 2026
Camden-Camden Dupont 115 kV Line ²	DEP	Rebuild	\$9,372,000	Nov 2024

Note 1 : Cost Estimate is fully burdened with contingency and can change over the project life cycle due to labor and materials costs.

Note 2 : Upgrade proposed to be included in NCTPC 2023 Local Transmission Plan



2023 Carolinas Resource Plan



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Table L-2: DEC and DEP Transmission Under Construction or Approved for Construction⁶

DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2024	Aquadale PV (50 MW)		100		New
DEC	2024	Blackburn PV (60.1 MW)		100		New
DEC	2024	Brookcliff PV (50 MW)		100		New
DEC	2024	Hornet PV (75 MW)		100		New
DEC	2024	IBM Tap	GE Aircraft Tap	100	200 ¹	Upgrade
DEC	2024	Mebane Tie	Piedmont EMC 10	100	143	New
DEC	2024	Newberry PV (74.5 MW)		100		New
DEC	2024	Oakboro PV (40 MW)		100		New
DEC	2024	West River PV (40 MW)		100		New
DEC	2024	Wilkes 230/100 kV Transformer		230/100	448	New
DEC	2024	Woodruff Tie	BMW	100		New
DEC	2025	Allen 230/100 kV Transformer (2)		230/100	448	Upgrade
DEC	2025	Cliffside	Peach Valley Tie	100		Upgrade
DEC	2025	Healing Springs PV (55 MW)		100		New
DEC	2025	Hodges Tie	Coronaca Tie	100	450	Upgrade
DEC	2025	Lee	Shady Grove (Lee Lines)	100	368 ¹	Upgrade
DEC	2025	Newberry Main	DESC Saluda	115	278 ¹	Upgrade
DEC	2025	North Greenville 230/100 kV Transformer		230/100	448	Upgrade
DEC	2026	Boyd Switching Station		230		New
DEC	2026	Bush River Tie	Laurens Tie	100	368 ¹	Upgrade
DEC	2026	Creto Tie	Coronaca Tie	100	404	New
DEC	2026	Hass Creek Switching Station		230		New
DEC	2026	Hilltop Tie	Shelby Tie	100		Upgrade
DEC	2026	Lee	Shady Grove (Piedmont Lines)	100	368 ¹	Upgrade
DEC	2026	Lyle Creek Switching Station		100		New
DEC	2026	North Greensboro Tie	Greensboro Main (Page)	100	368 ¹	Upgrade
DEC	2026	North Greensboro Tie	Greensboro Main (Guilford)	100	368 ¹	Upgrade
DEC	2026	Oakvale Tie	East Greenville	100		Upgrade
DEC	2026	Statesville Tie	Perth Road	100		New
DEC	2026	Wylie	Indianland Ret	100		New
DEC	2026	Wylie Hydro	Woodlawn Tie	100	240	Upgrade
DEC	2027	Lancaster Main	Monroe Main	100	242	Upgrade
DEC	2028	Dixon School Road	New Customer	230		New
DEC	2028	Harrisburg Tie	Amity	100		Upgrade
DEC	2028	Lakewood Tie	Woodlawn Tie	100		Upgrade
DEC	2028	Lee CC	Lee Steam	100	484	New
DEC	2028	Mebane Tie	Pleasant Garden Tie	100		Upgrade
DEC	2028	Oak Hollow Switching Station		100		New
DEC	2028	Shelby Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Concord Main	Winecoff Tie	100		Upgrade
DEC	2029	Concord Main	Harrisburg Tie	100		Upgrade
DEC	2029	Harrisburg Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Hodges 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Newport Tie	Morning Star Tie	230	421	New

⁶ Table L-2 lists projects 100 kV and above pursuant to Rule R8-60(ii) that are under construction or approved by Duke Energy for construction.

Appendix L | Transmission System Planning and Grid Transformation

DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2029	Tiger Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Wildcat Tie	Westfork	100		Upgrade
DEC	2030	Dan River	N Greensboro	100	242 ¹	Upgrade
DEC	2030	Lawsons Fork	W Spartanburg	100		Upgrade
DEC	2030	North Greenville	Marietta	100	484	Upgrade
DEC	2030	Research Triangle	Ellis Rd	100		Upgrade
DEC	2030	Shelby Tie	Cliffside	100		Upgrade
DEC	2031	Marshall Ret	Lookout Tie	100		New
DEC	2031	McGuire	Marshall	230		Upgrade
DEC	2032	Morning Star 230/100 kV Transformer (3)		230/100	448	Upgrade
DEC	2033	Dan River	Sadler (Wolf Creek)	100	242 ¹	Upgrade
DEC	2033	Dan River	Sadler (Reidsville)	100	242 ¹	Upgrade
DEC	2034	Winecoff Tie	Conley	100	484	Upgrade
DEP	2023	Havelock 230/115 kV Transformers		230/115	336	Upgrade
DEP	2023	Pig Basket Creek PV (80 MW)		230		New
DEP	2023	Porters Neck Tap	Porters Neck	230	442	New
DEP	2023	Wateree 115/100 kV Transformers (2)		115/100	336	Upgrade
DEP	2024	Camden	Camden Dupont	115	313	Upgrade
DEP	2024	Loftins Crossroads PV (75 MW)		230		New
DEP	2025	Arden Tap	Arden	115	280	New
DEP	2025	Carthage 230/115 kV Transformer Substation		230/115	336	New
DEP	2025	Craggy	Enka	230	644	New
DEP	2025	Weatherspoon	Marion	115	313	Upgrade
DEP	2026	Camden Junction	DPC Wateree	115	313	Upgrade
DEP	2026	Cape Fear	West End	230	1195	Upgrade
DEP	2026	Castle Hayne	Folkstone	115	296	Upgrade
DEP	2026	Erwin	Fayetteville East	230	1195	Upgrade
DEP	2026	Fayetteville	Fayetteville Dupont (4.9 miles)	115	313	Upgrade
DEP	2026	Holly Ridge North 115 kV Switching Station	JOEMC Folkstone POD	115	296	New
DEP	2026	Kingstree West PV (74.9 MW)		115		New
DEP	2026	Maxton	Pembroke	115	313	Upgrade
DEP	2026	Robinson	Rockingham	230	1195	Upgrade
DEP	2026	Sumter	DESC Eastover	115	270	Upgrade
DEP	2026	Weatherspoon	LREMC West Lumberton	115	313	Upgrade
DEP	2027	Robinson	Rockingham	115	310	Upgrade
DEP	2028	Delco	Leland Industrial	115	221	Upgrade
DEP	2028	Durham	Brier Creek	230	1195	Upgrade
DEP	2029	Cape Fear	Moncure	115	201	Upgrade

Note 1 : The MVA Capacity represents the capability for one circuit of the double circuit line.

Transmission System Planning to Ensure System Adequacy and Reliability

DEC and DEP manage the adequacy and reliability of their transmission systems and interconnections with neighboring entities through internal analysis and participation in regional reliability groups. The Companies' internal transmission planning team looks 10 years ahead at projected generating

Table L-7: Proposed Red Zone Expansion Plan (RZEP 2.0) Upgrades

Project	Owner	Project Description	Cost Estimate ^{1,2}	Potential In-Service Date
Broadway B/W 100 kV (Belton Tie-W.S. Lee Combined Cycle)	DEC	Rebuild	\$19,749,000	May 2028
Bush River 115/100 kV Transformers	DEC	Upgrade	\$8,523,000	May 2028
Champion B/W 100 kV (Bush River-New Berry PV)	DEC	Rebuild	\$29,114,000	May 2028
Clayton Industrial - Selma 115 kV	DEP	Rebuild	\$27,741,000	Sep 2028
Lilesville-Oakboro 230 kV Black³	DEP	Rebuild	\$54,470,000	Dec 2029
Lilesville-Oakboro 230 kV White³	DEP	Rebuild	\$54,470,000	Dec 2029

Note 1 : Class 5 Cost Estimate from the DEC 2022 DISIS Phase 2 Study Report.²⁷

Note 2 : Class 5 Cost Estimate from the DEP 2022 DISIS Phase 1 Study Report.²⁸

Note 3 : Cost Estimate includes upgrading the entire tie-line but excludes any upgrades to be identified as needed in the DEC Oakboro 230 kV substation.

Status Update on Transmission Expansion Plan Projects and Benefits from These Upgrades

Table L-8 below reflects the 14 RZEP projects approved through the Local Transmission Planning process as outlined in the DEC and DEP Joint OATT, Attachment N-1. For the 2022 DISIS, there were 11 solar facilities representing over 760 MW in the Phase 1 study that identified dependencies on one or more of the four DEC RZEP projects. There were nine solar facilities representing over 530 MW in the Phase 2 study that identified dependencies on one or more of the four RZEP projects. For the 2022 DISIS, there were 30 solar facilities representing over 2.4 GW in the Phase 1 study that identified dependencies on four of the 10 DEP RZEP projects. There were 12 solar facilities representing over 830 MW in the Phase 2 study that identified dependencies on four of the 10 DEP RZEP projects. Included in Table L-8 is the July 2023 status of all 14 RZEP projects including an updated cost estimate reflecting a fully burdened cost with contingency included. It should be noted that all 14 RZEP projects are on or ahead of the original planned in-service date schedule. The aggregated cost estimates for the projects, inclusive of burdens and contingency, have increased from \$554 million to \$576 million. Additionally, the Camden-Camden Dupont 115 kV upgrade, one of the original 18 recommended RZEP upgrades and supported by the summer 2022 DEP cluster-type study results, is included in Table L-8 as being proposed for inclusion in the 2023 Local Transmission Plan as presented in the 2022 Plan Mid-Year Update Report. All of the project status updates were provided in the Semi-Annual

²⁷ Duke Energy Carolinas, LLC 2022 Definitive Interconnection System Impact Study Phase 2 Report – Rev. 1 July 7, 2023, available at [https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_\(Phase_2\)_Report_rev1.pdf](https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report_rev1.pdf).

²⁸ Duke Energy Progress, LLC 2022 Definitive Interconnection System Impact Study Phase 1 Report November 23, 2022, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_DISIS_Phase_1_study_report_11-23.pdf.

Report on Status of Transmission Upgrades and Status Report on NCTPC Process under NCUC
Docket No. E-100, Sub 190T.

Table L-8: Proposed Red Zone Expansion Plan (RZEP 1.0) Project Status

Project	Owner	Project Description	Cost Estimate ¹	Planned In-Service Date
Lee 100 kV (Lee-Shady Grove)	DEC	Rebuild	\$39,660,000	Aug 2025
Piedmont 100 kV (Lee-Shady Grove)	DEC	Rebuild	\$40,080,000	Aug 2026
Newberry 115 kV (Bush River-DESC)	DEC	Rebuild	\$34,583,000	Apr 2025
Clinton 100 kV (Bush River-Laurens)	DEC	Rebuild	\$86,091,000	Oct 2026
Cape Fear Plant-West End 230 kV Line	DEP	Rebuild	\$83,033,000	Jun 2026
Erwin-Fayetteville East 230 kV Line	DEP	Rebuild	\$95,826,000	Jun 2026
Erwin-Fayetteville 115 kV Line	DEP	Rebuild	\$24,083,000	Jun 2025
Fayetteville-Fayetteville Dupont 115 kV Line – 3.2-mile section	DEP	Rebuild	\$15,574,000	Dec 2024
		Redundant		
Milburnie 230 kV Substation	DEP	Bus Protection	\$5,205,000	Apr 2026
Weatherspoon-Marion 115 kV Line	DEP	Rebuild	\$21,167,000	Dec 2025
Camden Junction-DPC Wateree 115 kV Line	DEP	Rebuild	\$15,909,000	Dec 2026
Robinson Plant-Rockingham 115 kV Line	DEP	Rebuild	\$42,293,000	Jun 2027
Robinson Plant-Rockingham 230 kV Line	DEP	Rebuild	\$49,020,000	Jun 2026
Fayetteville-Fayetteville Dupont 115 kV Line – 4.9-mile section	DEP	Rebuild	\$15,574,000	Apr 2026
Camden-Camden Dupont 115 kV Line ²	DEP	Rebuild	\$9,372,000	Nov 2024

Note 1 : Cost Estimate is fully burdened with contingency and can change over the project life cycle due to labor and materials costs.

Note 2 : Upgrade proposed to be included in NCTPC 2023 Local Transmission Plan.

Impacts for Standalone Storage Interconnections

Large scale standalone storage will continue to migrate to proactively selected sites such as retired coal sites that should minimize network upgrades relative to early projects and potentially garner the additional 10% Inflation Reduction Act of 2022²⁹ ("IRA") energy community tax credit. Additionally, locating standalone battery storage at transmission substations near load centers where the land availability for solar is not required should reduce the need for transmission network upgrades as well. In addition, the existing communications infrastructure can be leveraged at these locations.

²⁹ Inflation Reduction Act, S. Con. Res., 117th Cong. (2022).



INDIANA INTEGRATED RESOURCE PLANNING REPORT

to the:
Indiana Utility Regulatory Commission

Appendix – Volume 1

Submitted Pursuant to:
Commission Rule 170 IAC 4-7

March 28, 2025



**Indiana Michigan Power Company
2024 IN IRP: Appendix 1
Exhibit H: Transmission Projects**

Exhibit H Transmission Projects

23rd Street Station Rebuild: This project will rebuild 23rd Street station to address equipment material condition, performance and risk in Muncie, IN. The two 138/69/34.5kV transformers will be replaced and the 138kV and the 34.5kV will be rebuilt in a ring bus configuration.

- Project cost: \$5 million

23rd Street – Blaine Street Line Rebuild: This project will rebuild approximately 1.19 miles of 23rd Street-Blaine 69kV line (to be operated at 34.5kV) between structures 1-13 and structures 27 - 49 to address equipment material condition, performance and risk in Muncie, IN.

- Project cost: \$7 million

Adams – Berne 69kV Structure Replacement: Due to equipment material condition and performance, this project replaces structures only for approximately 4.90 miles of the Adams – Berne 69kV line.

- Project cost: \$13 million

Albion Area Improvements: This project is PJM baseline and supplemental. This baseline portion will address a voltage violation by adding a low side circuit breaker at Albion station. The supplemental portion addresses equipment material, condition, performance, and risk by rebuilding the Wolf Lake 69kV Tap (as double-circuit), the Richland-TriLakes 69kV line (as double circuit), the Albion-Kendallville 138kV line; and performing rehab work at Albion and Kendallville stations.

- Project cost: \$47 million

Albion – Columbia Improvements: This project is retiring the Gateway-Tri-Lakes 69kV circuit and constructing a new 138kV double circuit capable greenfield line operating at 69kV between Wolf Lake and Tri-Lakes. A new 69kV breaker will be installed at Albion, 69kV breaker "A" at Gateway will be retired, and the capacitor and cap switcher will be replaced at Gateway.

- Project cost: \$33 million

Allen – Maddox 345kV Rebuild: This project will rebuild the 27.8 mile double circuit 345kV Allen-Maddox Creek 345kV, which is made up of circuits Allen-RP Mone 345kV and RP Mone-Maddox Creek 345kV, to address a thermal violation. This project will also replace 345kV breakers B1 and B at Maddox Creek and 345kV breakers M and M2 at East Lima.

- Project cost: \$50 million

Burr Oak AEP for Trinity WVPA: Wabash Valley Power Authority (WVPA) has requested a Transmission Interconnection at their existing Trinity 69kV delivery point. As Trinity will not be radially connected anymore, the Marathon switch will need to be removed and be replaced with a ring bus station to not create a three-terminal line. This project constructs Burr Oak station a three 69kV circuit breaker ring bus to connect to WVPA's 69kV line connecting to their Trinity station.

Indiana Michigan Power Company
2024 IN IRP: Appendix 1
Exhibit H: Transmission Projects

- Project cost: \$7 million

Colony Bay – Illinois Road: The Colony Bay – Illinois Rd 69kV line asset will be rebuilt and reconducted to address equipment material condition, performance, and risk. In order to achieve this, AEP plans to rebuild the 1960's wood poles (2.7 miles), re-conductor (2.8 miles) and the 1960's aluminum conductor of the Colony Bay – Illinois Rd single circuit 69kV 6.9 mile line. In order to support this line rebuild, the 69kV POP switches (qty. 2) at Aboite 69kV station will be replaced and owned by AEP.

- Project cost: \$11 million

Deer Creek – Makahoy: Rebuild 16.5 miles of the Deer Creek - Makahoy 138kV line. Rebuild 3.9 miles of the Deer Creek - Makahoy 138kV line as double circuit west from Deer Creek. Operate as double circuit to allow for bringing the Grant line into Deer Creek eliminating the 3 terminal line.

- Project cost: \$46 million

Delaware – Kenmore Rebuild: This project will rebuild ~3.7 mile double circuit Delaware - Kenmore, this line will be comprised of ~1.3 miles of underground and ~2.4 miles of overhead and will be built at 69kV standards but energized at 34.5kV to address equipment material condition, performance, and risk in Muncie, IN.

- Project cost: \$30 million

Delaware – Sorenson Markle Delivery Point: WVPA has requested a new 12 MW delivery point in Markle Indiana. To serve this delivery point, a new switch will be installed on the Delaware-Sorenson 138kV line. From the new switch, a greenfield ~2.5 mile 138kV radial line will be installed to the customer station.

- Project cost: \$9 million

East Elkhart – Mottville Rebuild/Re-route: On the East Elkhart – Mottville Hydro 138kV circuit, ~3.95 miles of greenfield line will be constructed from structure 96 to the newly constructed RV Capital station and remove ~3.75 miles of the existing circuit from structure 96 to structure 121. This will effectively address asset renewal needs while eliminating a hard tapped radial feed.

- Project cost: \$31 million

Fall Creek 345kV Circuit Breaker Replacement: This project addresses equipment material condition, performance, and risk. This project will retire and remove two 345kV circuit breakers (to be funded by AES). Two new 345kV circuit breakers will be installed and owned by AEP towards AES's Noblesville and Desoto station.

- Project cost: \$9 million

Glenbrook Area Improvements: This project will build a new 138/12kV Beckwith station to replace and retire Glenbrook station. The new Beckwith station will be connected to the Industrial Park – Spy Run

**Indiana Michigan Power Company
2024 IN IRP: Appendix 1
Exhibit H: Transmission Projects**

138kV circuit. AEP will retire the 4.25 mile Industrial Park – Spy Run 34.5kV line as well as Glenbrook 34/12kV substation. The Industrial Park transformer will be replaced. All 34.5kV assets at Wallen will be retired and the 3.5 mile Wallen – Industrial Park 34.5kV line will be retired.

- Project cost: \$11 million
- **Hamilton Area Improvements:** Two-way service will be provided to Hamilton and customers by installing a new 69kV line to Butler to address Hamilton Station customer outages due to maintenance, storm outages, and fault load dropping on the radial line from Butler. Customers will be served from a new breaker-and-half Teutsch Station and the existing Butler Station will be retired, eliminating exposure to line faults. A new 69kV circuit breaker will replace the motor operated breaker switches (MOABs) at Hamilton.
 - Project cost: \$20 million
- **Hayes AES/DP&L 138kV Connect:** This project is a Transmission owner connection request and baseline project which constructs Hayes station a four 138kV circuit breaker ring bus and will install a new ~0.19 miles 138kV line to the Indiana/ Ohio State line to connect to DP&L's 138kV line connecting to their Blazer station. A new 138kV line ~0.05 miles will be built from Hodgkin station to Hayes station. Additionally, 138kV metering will be installed.
 - Project cost: \$15 million
- **Hillcrest – Adams 69kV Line Rebuild:** AEP has identified overload criteria violations and multiple condition and performance needs on Hillcrest-Adams 69kV. Ferguson station will be rebuilt on the nearby 138kV line as Baer to move it out of the FAA flight path. The Ferguson – Bluffton 69kV Branch and Adams – Bluffton 69kV Line will be rebuilt and re-routed to accommodate Kinnerk station served out of Hillcrest station via 3.55 miles radial line and Uniondale (REMC) station served out of Kingsland station via 4.3 miles radial line. Oil filled circuit breakers at Kingsland Station, manufactured in 1969, will be replaced with new circuit breakers.
 - Project cost: \$120 million
- **Huguenard Area Improvements:** This project will retire the ~12.9 mile Lincoln – Tillman 34.5kV line due to equipment material condition, performance and risk in Ft Wayne Indiana. This project will build a new ~2.4 mile 138kV double circuit line extension from the Lincoln – Allen 138kV line to the new 138/34.5kV Huguenard station. Huguenard will be a 138/34.5kV station with a 3CB 138kV ring with the transformer and 34.5kV CB being re-used from Tilman station.
 - Project cost: \$19 million
- **Hummel Creek:** This project addresses equipment material condition, performance and risk. The project constructs ~4.48 miles of new 69kV line (to be operated at 34.5kV) between Hummel Creek and Marion Plant Stations.
 - Project cost: \$11 million
- **Jay – College Corner:** This project rebuilds 62.4 mile 138kV Jay – College Corner line due to the condition and risk associated with t structures of this age and type.
 - Project cost: \$114 million

**Indiana Michigan Power Company
2024 IN IRP: Appendix 1
Exhibit H: Transmission Projects**

- **Madison – Pendleton Line Rebuild:** This project rebuilds 4.17 miles of the Madison – Pendleton 138kV line to address equipment material condition, performance and risk. In addition, the project expands Meadowbrook station to address operational concerns by adding 2- 138kV circuit breakers to eliminate the 3 terminal line.
 - Project cost: \$8 million
- **Magley – Decatur Rebuild:** This project is rebuilding 5.88 miles of 69kV to address equipment material condition on the Magley-Decatur 69kV line.
 - Project cost: \$12 million
- **Eastern Marion Improvements:** This project is rebuilding 17.67 miles of the Deer Creek – Hartford City 69kV line, retiring the Deer Creek – Hummel Creek 34.5kV line, retiring the Jonesboro – Gas City 34.5kV line, retiring the Jonesboro Extension 34.5kV line, retiring the remaining Deer Creek – Alexandria 34.5kV line (2.2 miles), retiring the de-energized Deer Creek Extension 34.5kV line and upgrading Hummel Creek station to address equipment material condition, performance and risk issues in Marion, Indiana.
 - Project cost: \$41 million
- **McKinley – Industrial Park:** This project will rebuild the Industrial Park – McKinley 138kV line and replace risers at Bass to address equipment material/condition, performance and risk in Ft. Wayne, Indiana as well as thermal violations. The supplemental portion of this project rebuilds the ~4.59 mile portion of the Industrial Park – McKinley line asset which includes ~1.9 miles of existing double circuit, ~1.5 miles of existing single circuit and ~1.4 miles of single circuit that'll be rebuilt double circuit with the Bass – McKinley 34.5kV asset. The baseline portion of the project will replace overloaded risers to alleviate the thermal overloads at Bass Station.
 - Project cost: \$9 million
- **Eastern Melita Area Improvements:** AEP will build new 69kV lines from Melita to Anthony 69kV and a double circuit extension from Lincoln to connect to the Lincoln – Water Pollution 69kV line. A new single circuit 34.5kV Maumee Extension will connect Maumee Sw to the Lincoln – Water Pollution line. Anthony station will be rebuilt as a 69/12kV station, Melita will have a 69kV CB added, and Storm Water, Omnisource, Water Pollution and Lincoln will have minor work done to bring them to 69kV operation. Filtration Switch and the Skid station will be retired.
 - Project cost: \$15 million
- **North Melita Area Improvements:** This project will rebuild the 2.59 mile 69kV wood line north of Melita while retiring the 2.14 mile 34.5kV line section south of Melita along with the 34.5kV breaker at McKinley. To accommodate the Melita connection, a new 69kV breaker will be installed at Melita, the transformer at Fulton will be replaced and transformer 3 at Spy Run will be replaced to bring the Spy Run – Melita line to 69kV operation.
 - Project cost: \$25 million
- **Northern Muncie Area Improvements:** The Delaware 34.5kV station, the Delaware – Jay 34.5kV, 20 mile line and the Delaware – Haymond 34.5kV, 2.5 mile line have all been identified as rehab

**Indiana Michigan Power Company
2024 IN IRP: Appendix 1
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candidates. AEP is installing a new 138kV Perch station and retiring the 20-mile Delaware – Jay asset. AEP will also be rebuilding the Delaware – Haymond line as well as rebuilding the Delaware 34.5kV station as a ring bus to address the issues identified.

- Project cost: \$7 million
- Pendleton – Makagoy Line Rebuild: This project will rebuild the Makahoy – Pendleton 138kV line (approximately 15 miles), replaces the Pendleton 138/34.5kV transformer #2 and removes the Pendleton transformer # 1 which is no longer in service.
 - Project cost: \$27 million
- Pettit Avenue – Melita: This project will rebuild ~1.9 miles of 69kV line on the Hillcrest-Webster 69kV line asset to address equipment material condition, performance and risk.
 - Project cost: \$12 million
- Project Amazing: This project will serve a new 1,100 MW customer on the 345kV lines south of Olive station in the New Carlisle, Indiana area. To serve the customer, the Dumont – Elderberry and Dumont – Sorenson 345kV lines will be tapped and two new greenfield 345kV stations, Larrison Drive and New Prairie, will be constructed along with (6) customer radials from each greenfield station to the customer delivery points (~0.07 miles). The Kenzie Creek – Thomson 345kV circuit will have sag mitigation work performed to help increase the operating temperature of the line to achieve higher ratings. Work at Olive is also required, which includes replacing 345kV circuit breakers B, B1, B2, D1, and D2 along with bringing in the Dumont – Sorenson 345kV circuit that passes outside the station into a new string (C).
 - Project cost: \$188 million
- Project Discovery: This project will serve a new 1,200 MW customer on the 138kV lines west of Allen station. To serve the customer, Allen station will be expanded with (2) new 345/138kV transformers and circuit breakers. A greenfield Zodiac station with (26) 138kV breakers will be installed to cut in AEP lines Allen-Lincoln #1 & #2, Allen-Hillcrest and Allen-Magley along with (10) customer radials from Zodiac station to the customer delivery points (~0.75 miles). The (2) 138kV double circuit lines (~4.1 miles each) will be rebuilt from Allen station to new Zodiac station.
 - Project cost: \$169 million
- Robison Park – Lincoln: AEP will rebuild the 7.8 mile 138kV single circuit Rob Park – Lincoln line asset and add a 138kV tie breaker to Trier station to remove the 4 MOAB's in series. Trier station will also have a DICM expansion.
 - Project cost: \$25 million
- Robison Park – McKinley: To address equipment material/condition performance on the Robison Park-McKinley/Wallen 69kV line AEP will rebuild ~3.24 miles of single circuit 69kV line.
 - Project cost: \$6 million

Indiana Michigan Power Company
2024 IN IRP: Appendix 1
Exhibit H: Transmission Projects

- Robison Park – South Hicksville 69kV Line Rebuild: AEP has identified condition and performance issues on the Robison Park-South Hicksville 69kV line and a thermal violation for N-1-1 type contingency will be mitigated by rebuilding 2.2 miles of the North Hicksville – Butler 69kV line and 33.22 miles of the South Hicksville – Robison Park Tie 69kV line.
 - Project cost: \$21 million
- Robison Park – Sowers: This project will re-conductor 18.1 miles of double circuit 138kV conductor and rebuild 13.7 miles of the 138kV line (double circuit capable) between Robinson Park and Sowers stations. To address potential load growth with potential customers, double circuit towers were used for this rebuild for future projects. The project includes station upgrades at Grabill station to facilitate the line rebuild, complete security light upgrades at Grabill station, and install a MOAB toward Sowers station and a new switch towards Robinson Park at Grabill station.
 - Project cost: \$42 million
- Winchester Area Improvements – East: This project will address planning criteria violations on the Winchester – Anchor Hocking 69kV line and 138/69/12kV Transformer #1 at Randolph station. Supplemental upgrades are also included to expand Randolph, Winchester, and Anchor Hocking stations to address asset performance, equipment condition, risk of failure, and operational flexibility.
 - Project cost: \$19 million
- Winchester Area Improvements – West: This project will rebuild 19.1 miles of the Modoc – Winchester 69kV line and Buena Vista – Lynn 69kV lines to address equipment material condition, performance, and risk. The project includes upgrades to expand Modoc and Lynn stations, rebuild Huntsville Switch, and a new switch to serve the tie to Lobdell Station.
 - Project cost: \$23 million

PUBLIC DISCLOSURE

Table 5: B2025 Technology Cost and Performance Summary

1885

Technology	Winter Capacity (MW)	ELCC	Average Heat Rate (Btu/kWh)	Round Trip Efficiency	Fixed Capacity Factor	Overnight Cost (2024\$/kW)	Recurring Fixed Cost ² (2024\$/kW-yr)	Variable O&M (\$/MWh)	Asset Life (Yrs)
Natural Gas Combined Cycle (NGCC)	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
NGCC with Local CCS	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
NGCC with Distant CCS	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combustion Turbine with SCR, Oil Winter (CT w SCR)	REDACTED	100%	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Solar Photovoltaic (PV) - Single Axis Tracker (SAT)	REDACTED	0%			REDACTED	REDACTED	REDACTED		REDACTED
Onshore Wind Power	REDACTED	35%			REDACTED	REDACTED	REDACTED		REDACTED

² Recurring fixed costs include Fixed O&M, Maintenance Capital, and Natural Gas Firm Transportation.

PUBLIC DISCLOSURE

Technology	Winter Capacity (MW)	ELCC	Average Heat Rate (Btu/kWh)	Round Trip Efficiency	Fixed Capacity Factor	Overnight Cost (2024\$/kW)	Recurring Fixed Cost ² (2024\$/kW-yr)	Variable O&M (\$/MWh)	Asset Life (Yrs)
Lithium-ion Battery Energy Storage System (BESS) - 4 Hr	REDACTED REDACTED	0-3000 MW :95% 3001-6000 MW : 75% 6001-9000 MW : 50% 9001+ MW : 25%		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Medium Duration Energy Storage System	REDACTED REDACTED	100%		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Nuclear (AP-1000)	REDACTED	100%				REDACTED	REDACTED		REDACTED

**2024 Joint Integrated
Resource Plan of
Louisville Gas and Electric
Company and Kentucky
Utilities Company**



PPL companies

Case No. 2024-00326

Volume III

2024 IRP Technology Update



PPL companies

**Generation Planning & Analysis
October 2024**

CONFIDENTIAL INFORMATION REDACTED

Table 1: Fully Dispatchable Resources (2030 Installation; 2030 Dollars)

	SOCT	NGCC	SMR
Summer Capacity (MW) ¹	243	645	300
Winter Capacity (MW)	258	660	300
Heat Rate (MMBtu/MWh) ²	9.5	6.3	9.2
Capital Cost (\$/kW) ³	1,636	2,121	9,765
Fixed O&M (\$/kW-yr) ⁴	6.9	7.8	166
Firm Gas Cost (\$/kW-yr) ⁵	19	15	N/A
Variable O&M (\$/MWh) ⁷	N/A	0.23	3.17
Start Cost (\$/Start) ⁶		N/A	N/A
Hourly Operating Cost (\$/Hour) ⁸	N/A		N/A
Fuel Cost (\$/MWh) ⁹			13.45
Investment Tax Credit ¹¹	N/A	N/A	40%
Earliest In-Service Year ¹²	2030	2030	2039

¹ Capacity is the net installed capacity ("ICAP").

² Heat rate is the full load net heat rate.

³ Capital cost is the overnight capital expenditure required to achieve commercial operation. Cost of financing is modeled through construction profiles for each resource type.

⁴ Fixed operation and maintenance costs are operation and maintenance costs that do not vary with generation output. For SOCT and NGCC resources, fixed O&M includes fixed costs for a long-term service agreement ("LTSA").

⁵ Firm gas transportation costs are costs associated with reserving firm gas-line capacity.

⁷ Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit energy basis.

⁶ Start costs are starts-based variable LTSA costs for SOCT.

⁸ Hourly operating costs are hours-based variable LTSA costs for NGCC.

⁹ Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.

¹¹ In accordance with the current tax credits, the Companies assumed nuclear SMR resources that are in-service by year 2039 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2040 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2041 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2042 or later would begin construction in 2036 or later and not receive any tax credits. Further cost reductions may be possible by utilizing existing sites.

¹² Earliest in-service year is the first year the Companies expect a resource can be feasibly built based on permitting and construction timelines as well as lead times for electrical equipment such as generator step up transformers.

DESC IRP Stakeholder Advisory Group Session XVI

V. 2025 IRP Update



Supply-Side Inputs Candidate Resource Options

Preliminary - Still a Work In Progress

Available Resources	Capital Cost		Capacity (MW)	Source Of Data
	2024 IEP Update (\$/kW)	2025 IEP Update (\$/kW)		
New 2nd CC Greenfield	1,226	1,449	1309	Domestic Energy Project Construction Group
New 3rd CC Greenfield	1,992	1,449	665	Domestic Energy Project Construction Group
New (3) 2nd Combined Cycle 50% Shared Brownfield	NA	Pending	976	Domestic Energy Project Construction Group
New 300 Adv-Class Frame CT Greenfield	NA	1,404	450	Domestic Energy Project Construction Group
New 200 F-Class CT Greenfield	1,472	1,441	402	Domestic Energy Project Construction Group
New 400 Aero CT Greenfield	NA	1,285	210	Domestic Energy Project Construction Group
New 200 Aero CT Greenfield	2,451	1,372	305	Domestic Energy Project Construction Group
New 1st F-Class CT Unghart CT #9 Brownfield	NA	Pending	201	Domestic Energy Project Construction Group
New 300 Aero CT Bushy Park CT #2 Brownfield	NA	Pending	52	Domestic Energy Project Construction Group
New Small Modular Reactor	12,385	12,181	274	DOE, 2024 AED
New Solar *	1,375	1,449	100	DOE, 2024 AED
New Solar PPA *	1,375	1,449	100	DOE, 2024 AED
New Solar Plus Storage *	NA	2,500	300	DOE, 2024 AED
New Battery 4 hour *	1,791	2,486	100	DOE, 2024 AED
New Battery 8 hour *	NA	1,877	100	DOE, 2024 AED
New Offshore Wind *	4,135	1,449	200	DOE, 2024 AED

* Includes Grid Interconnection





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For Immediate Release

NEWS RELEASE

PSC to Begin 6-Month IRP Process Georgians Encouraged to Participate

Feb. 7, 2025 – (ATLANTA) The Georgia Public Service Commission received Georgia Power's filing for the utility's 2025 Integrated Resource Plan on Jan. 31.

The process to approve the plan will include three public hearings: March 25-28, May 27-30 and a rebuttal hearing on June 23-25. The first hour of each day's hearing will be reserved for public comment. Members of the public can also send comments via mail, email or via the PSC's electronic portal, available on the homepage of the PSC's website www.psc.ga.gov.

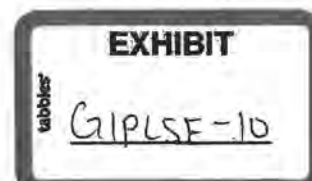
The IRP is filed every three years to set Georgia Power energy production. Although the plan is updated every three years, the plan is a 20-year outlook of energy production amounts and methods.

"My fellow Commissioners and I make every effort to hear from Georgians during the IRP process," said PSC Chairman Jason Shaw. "As we weigh evidence presented to us by expert witnesses, engineers and energy analysts, we also read all comments sent by the public and listen to every public witness who takes the time to speak at the hearings. It is a vitally important part of the IRP process."

Now that the IRP has been filed, the PSC's Public Interest Advocacy Staff will utilize experts in finance and energy production to analyze Georgia Power's plan. The IRP will be litigated over the next six months where PSC staff request data from Georgia Power, expert witnesses file testimony, and the Commissioners will hold the hearing that will include witnesses and cross examination. As many as two dozen outside intervenors will join the process and are likewise able to file documents, present witnesses and cross-examine other witnesses.

On July 15, at the PSC's regularly scheduled Administrative Session, the Commissioners will vote on the final version of the Georgia Power IRP including all changes made during the process.

This is a link to the 2025 IRP docket on the PSC's website. It will include all information on the case: <https://psc.ga.gov/search/facts-docket/?docketId=56002>



This is a link to the Procedure and Scheduling Order which provides a schedule of all relevant dates including dates of filings and hearings: <https://psc.ga.gov/search/facts-document/?documentId=221169>

For more information on the Commission, see the PSC website at <https://psc.ga.gov/>

###

1 A. (Witness Grubb) -- it shows a project cost.
2 And then on Exhibit 6, which is the Carolinas Transmission
3 Planning Collaborative, is that total where it shows --
4 like page 63, 313, is that a total of all those projects
5 above?

6 I'm just trying to get my -- trying to get
7 oriented.

8 Q. No. This one is -- this is -- this one lists
9 an estimated cost project by project in the Carolinas
10 Collaborative Transmission Plan. So each -- it's dozens
11 of pages of specific projects with their estimated costs.

12 A. (Witness Grubb) But, again, just trying to
13 be -- so Carolinas, it's a subtotal of the projects above
14 it is what I was trying to clarify?

15 Q. Oh, no. These are two separate processes.

16 A. (Witness Grubb) Yeah. I get that -- okay. I
17 get that Domin- -- okay. I'll -- I'll wait.

18 Is it me? Okay.

19 Q. Okay. When you discuss projects as part of
20 the ITS meetings, do you discuss costs?

21 A. (Witness Robinson) We do. That is a very
22 important part of the joint planning process and it has to
23 be known so that we can assign projects based on parity
24 and we understand our parity forecast.

25 Q. Does Georgia Power compete with ITS

EXHIBIT

G1PLSF-11

0544

0195

1 participants to build transmission in Georgia?

2 A. (Witness Robinson) We do not. We each assign
3 each other transmission or projects based on ownership.
4 And those projects are owned by each participant and taken
5 to COD, or in-service, and then they bring those actual
6 costs into parity for our parity calculation that I talked
7 about earlier. So we do not compete to build
8 transmission.

9 Q. Okay. Does Georgia Power compete against
10 anybody to build transmission?

11 A. (Witness Robinson) Not in the state of
12 Georgia --

13 Q. Okay.

14 A. (Witness Robinson) -- because of the
15 Integrated Transmission System.

16 Q. Sure.

17 A. (Witness Robinson) And that's the benefit of
18 having an Integrated Transmission System is that we're
19 jointly planning the system together and making economic
20 decisions that are in the best interest of all of our
21 customers.

22 A. (Witness Grubb) But you do get people to do
23 that work for us, which is -- from the trade secret
24 standpoint, that's what we're looking at is we're going to
25 build those projects. We don't self-build all of them.

**Dominion Energy South Carolina
Planned Transmission Projects \$2M and above Total
5 Year Budget**

**Queensboro - Ft Johnson 115 kV & Queensboro-Bayfront 115kV
(Queensboro-James Island Sect)**

Project ID
6807 B

Project Description
Replace the Queensboro – Ft Johnson 115 kV Line and structures as they have reached the end of life.

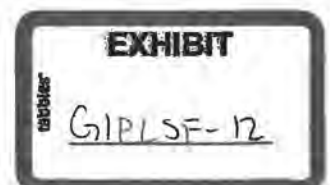
Project Need
This project is required due to address end of life issues.

Project Status
In Progress

Planned In-Service Date
12/31/23

Estimated Project Cost						
Previous	2024	2025	2026	2027	2028	Total*
\$4,604,301	\$800,000	\$0	\$0	\$0	\$0	\$5,404,301

*Total Estimated Amount applied to 2024 Rate Base Calculation



Appendix C Transmission Plan Major Project Listings – Reliability Projects



Project ID	Reliability Project (Previously in Plan)	Transmission Owner	Status ¹	Projected In-Service Date	Estimated Cost (\$M) ²	Initiating Study Type ³
E190037	Havelock 230/115 kV Banks 1 & 2, Replace	DEP	In-Service	7/23/2024	8	TPL
DFYF00152	Castle Hayne-Folkstone 230 kV Line – Porters Neck 230 kV Tap Line, Construct	DEP	In-Service	8/19/2024	38	TPL
W190286	Wateree 100 kV Line (Great Falls-Wateree), Upgrade	DEC	In-Service	12/1/2024	12	TPL
E180030	Craggy-Enka 230 kV Line, Construct	DEP	Underway	6/1/2025	93	TPL
F170628C	Rocky Mount – Battleboro 115 kV Line, Reconductor	DEP	Underway	6/1/2025	13	AS
W220125	Breaker Station on Motley 100 kV Line for New Customer, Construct	DEC	Underway	6/1/2025	16	New Loads
NP09175	Wilkes 230/100 kV Tie Station, Construct	DEC	Underway	6/1/2025	63	TPL
W200379	Island Creek 44 kV, Conversion	DEC	Underway	12/1/2025	14	New Loads
W190242	Cokesbury 100 kV Line (Coronaca-Hodges), Upgrade	DEC	Underway	12/1/2025	29	TPL
W200126	South Point 100 kV Switching Station, Construct	DEC	Underway	12/1/2025	103	TPL
E210073	Carthage (Hill Crest) 230/115 kV Substation, Construct	DEP	Underway	6/1/2026	33	TPL
E220112	Asheville Plant – Oteen 115 kV West Line (Arden), Construct	DEP	Underway	6/1/2026	12	TPL
W200030	Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade	DEC	Underway	6/1/2026	14	TPL
E200161	Castle Hayne-Folkstone 115 kV Line, Rebuild	DEP	Underway	12/1/2026	89	TPL
F170824H	Weatherspoon – LOF 115 kV Line (Maxton-Pembroke), Reconductor	DEP	Underway	12/1/2026	19	TPL
E230059	Sumter – SCEG Eastover 115 kV Line (Kings Hwy – Shaw Field – Eastover), Reconductor	DEP	Underway	12/1/2026	27	TPL
W200042	Sevier 100 kV Line (East Greenville-Verdae Retail Tap), Upgrade	DEC	Underway	12/1/2026	20	TPL
W200039	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Construct	DEC	Underway	12/1/2026	41	TPL
W200599	Davidson River 100 kV Line (North Greenville-Marietta), Upgrade	DEC	Planned	6/1/2027	19	TPL

Project ID	Reliability Project (Previously in Plan)	Transmission Owner	Status	Projected In-Service Date	Estimated Cost (\$M)	Initiating Study Type
W230145	Hands Mill Switching Station, Construct	DEC	Underway	6/1/2027	67	New Loads
W200031	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	DEC	Underway	6/1/2027	69	TPL
W220387	Boyd Switching Station, Construct	DEC	Underway	6/1/2027	94	New Loads
W230245	Messer 230 kV Line (Dixon School Rd-Customer), Construct	DEC	Planned	12/1/2027	41	New Loads
W220209	Lyle Creek Switching Station, Construct	DEC	Underway	12/1/2027	112	New Loads
W220368	Haas Creek Switching Station, Construct	DEC	Underway	12/1/2027	91	New Loads
E220380	Asheboro – Siler City 115 kV Line, Reconductor	DEP	Underway	6/1/2028	41	New Loads
W170306	North Greenville 230 kV Tie Station, Upgrade	DEC	Underway	12/1/2028	34	TPL
W200061	Page and Guilford 100 kV Lines (Greensboro-North Greensboro), Upgrade	DEC	Planned	6/1/2029	30	TPL
W200172	Morning Star 230 kV Tie Station, Upgrade	DEC	Planned	6/1/2031	39	TPL
W200590	Crab Orchard 100 kV Line (Harrisburg-Amity), Upgrade	DEC	Planned	6/1/2033	15	TPL
W200262	Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade	DEC	Planned	6/1/2033	37	TPL
W200595	Westport 230 kV Line (McGuire-Marshall), Upgrade	DEC	Conceptual	6/1/2035	53	TPL
CTPCDEP01	Durham – RTP 230 kV Line, Reconductor	DEP	Conceptual	TBD	TBD	TPL
E210145	Holly Ridge North 115 kV Switching Station, Construct	DEP	Conceptual	TBD	12	TPL
CTPCDEP02	Weatherspoon – LOF 115 kV Line (Weatherspoon- LREMC West Lumberton), Reconductor	DEP	Deferred	TBD	27	TPL
CTPCDEP03	Falls – Franklinton (Franklinton – Franklinton Novo 115 kV Feeder), Construct	DEP	Conceptual	TBD	16	TPL
W220569	Concord 100 kV Line (Concord-Concord City Del 3), Upgrade	DEC	Conceptual	TBD	2.6	TPL
W230087	Kennedy 100 kV Line (Orchard-Newton Tap), Upgrade	DEC	Conceptual	TBD	8	TPL

Project ID	Reliability Project (Previously in Plan)	Transmission Owner	Status ¹	Projected In-Service Date	Estimated Cost (\$M) ²	Initiating Study Type ³
W220507	Cabarus 100 kV Line (Wildcat-Westfork), Upgrade	DEC	Conceptual	TBD	4.3	TPL
W200412	Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade	DEC	Conceptual	TBD	15	TPL
CTPCDEC01	Beulah 100 kV Line (Lookout-EnergyUnited Del 18), Upgrade	DEC	Conceptual	TBD	21	TPL
W230358	Hinkle 100 kV Line (Stamey-Statesville), Upgrade	DEC	Conceptual	TBD	7	TPL
W200173	Terrell 44 kV Line, Conversion	DEC	Conceptual	TBD	26	TPL
W200149	Reidsville and Wolf Creek 100 kV Lines (Dan River-Sadler), Upgrade	DEC	Conceptual	TBD	37	TPL
CTPCDEC02	Harley 100 kV Line (Tiger-Campobello), Upgrade	DEC	Conceptual	TBD	45	TPL
W230384	Oliver 230 kV Line (Marshall-Boyd), Upgrade	DEC	Conceptual	TBD	17	TPL
W200162	Dan River 100 kV Line (Dan River-North Greensboro), Upgrade	DEC	Conceptual	TBD	89	TPL
	Brush Creek, Construct STATCOM	DEP	Removed			New Loads
	Method – Milburn 115 kV North Line, Reconductor	DEP	Removed			TPL
	Rockingham - West End 230 kV West Line, Reconductor	DEP	Removed			TPL
Subtotal	Reliability Project (Previously in Plan)				\$1,711.1	

Project ID	Reliability Project (New to Plan >= \$5M)	Transmission Owner	Status ¹	Projected In-Service Date	Estimated Cost (\$M) ²	Initiating Study Type ³
E210150	Havelock 230 kV Substation, Upgrade	DEP	Underway	12/1/2025	7	TPL
W200010	Cherokee 100 kV Line (Peach Valley-Enola Retail), Upgrade	DEC	Planned	6/1/2026	8	TPL
W210192	Earl 100 kV Line (Customer Tap-Customer Tap), Upgrade	DEC	Planned	6/1/2026	12	TPL
E190092	Greenville - VEPCO Everetts 230 kV Line, Reconductor	DEP	Underway	12/1/2026	30	AS
W230158	Nanny Mountain 144 kV Line (Structure 73.0 – Customer Delivery), Upgrade and Partial Conversion to 100 kV	DEC	Planned	12/1/2026	7	TPL
W200148	Pinewood 100 kV Line (Lawsons Fork-Una Retail), Upgrade	DEC	Planned	6/1/2027	10	TPL
E240135	Sumter - SCEG Eastover 115 kV Line (Gold Kist Tap-Kings Hwy Section), Reconductor	DEP	Underway	12/1/2027	10	TPL
W230278	Shelby 230/100/44 kV Tie, Upgrade	DEC	Planned	6/1/2028	14	TPL
W200187	Harrisburg 230/100/44 kV Tie Station, Upgrade	DEC	Planned	12/1/2028	13	TPL
W230389	Sycamore B/W 100 kV (Longview-Lyle Creek), Upgrade and Network	DEC	Planned	6/1/2029	8	TPL
W200116	Hodges 230/100/44 kV Tie, Upgrade	DEC	Planned	6/1/2029	41	TPL
W200150	Troutman 44 kV Line, Upgrade and Partial conversion to 100 kV [Modification to 0110 in 2023 Plan - Additional Scope]	DEC	Planned	6/1/2029	45	TPL
W200413	Tiger Tie Autotransformer #5 (230/100 kV) Upgrade	DEC	Conceptual	TBD	7	TPL
W200144	Oak Hollow Switching Station, Construct	DEC	Conceptual	TBD	7	TPL
W200120	Dairyhill 100 kV Line (Shelby-CUSTOMER Tap), Upgrade	DEC	Conceptual	TBD	11	TPL
W230402	Ashe Street 100 kV Line (Durham-Ashe Street), Upgrade	DEC	Conceptual	TBD	12	TPL
W200582	Bethania and Shattalon 100 kV Lines (Rural Hall-Shattalon), Upgrade	DEC	Conceptual	TBD	15	TPL
W200034	Panther 100 kV Lines (Parkwood Tie-E Durham Tie), Upgrade and Network to E Durham Tie [Modification to 0096 in 2023 Plan - Splitting into Two Projects]	DEC	Conceptual	TBD	56	TPL
Subtotal	Reliability Project (New to Plan >= \$5M)				\$313	

Project ID	Reliability Project (New to Plan <= 15M)	Transmission Owner	Status ^a	Projected In-Service Date	Estimated Cost (\$M) ^b	Initiating Study Type ^c
E210076	Fayetteville 230/115 kV Bank #1, Upgrade 115 kV Disconnect Switches, Wave Traps, and CT Ratios	DEP	Underway	12/1/2024	3	TPL
E210227	Sutton – Castle Hayne 230 kV Line (Sutton - Wilmington Ninth & Orange), Upgrade Line Switch	DEP	Underway	12/1/2024	1	TPL
E210081	Richmond 500 kV Substation, Upgrade 230 kV Wave Trap, Disconnect Switches, and CT Ratio for the Laurinburg-Richmond 230 kV Line	DEP	Underway	6/1/2025	1.1	TPL
E220086	Sutton-Wallace 230 kV Line, (Crooked Run Solar-Wallace) Raise Section and Increase CT Ratios and Relay Settings at Wallace 230 kV Substation	DEP	Underway	6/1/2025	0.8	TPL
E230041	Richmond 500/230 kV Banks #1 & #2, Upgrade CT Ratios	DEP	Underway	6/1/2025	3.7	TSR
E190052	Jacksonville - Jacksonville City 115 kV East Line, Upgrade CT Ratio at Jacksonville	DEP	Underway	6/1/2025	0.2	TPL
W210382	Kennedy 100 kV Line, RAS (Grid Enhancing Technology) to Avoid Overloads on the Kennedy Lines	DEC	Underway	6/1/2025	0.8	TPL
W220516	Davidson River 100 kV Lines, RAS (Grid Enhancing Technology) to Avoid Overload on the Davidson River Lines	DEC	Underway	6/1/2025	1	TPL
E230081	Henderson 230/115 kV Banks #1 & #2, Upgrade CT Ratios and Relay Settings	DEP	Underway	12/1/2025	2.9	TPL
E220408	Vanderbilt - West Asheville 115 kV Line, Upgrade 115 kV CB and Switches	DEP	Underway	12/1/2025	2	TPL
W220537	Ashe Street Switching Station, RAS (Grid Enhancing Technology) to Avoid Overloads on Delta 100 kV Line [Originally Called Delta 100 kV Line, RAS in November Solutions]	DEC	Underway	12/1/2025	0.5	TPL
W230368	Mooresville Tie, RAS (Grid Enhancing Technology) to Avoid Overloads on Timber and Sherrill 100 kV Lines [Originally Called Timber 100 kV Line and Sherrill 100 kV Line, RAS in November Solutions]	DEC	Underway	12/1/2025	0.6	TPL

Project ID	Reliability Project (New to Plan <= \$5M)	Transmission Owner	Status ¹	Projected In-Service Date	Estimated Cost (\$M) ²	Initiating Study Type ³
W220539	Batte 100 kV Line, RAS (Grid Enhancing Technology) to Avoid Overloads on Batte Lines	DEC	Underway	12/1/2025	1.5	TPL
W220053	Shattalon Switching Station, RAS (Grid Enhancing Technology) to Avoid Overload on Bethania and Shattalon 100 kV Lines [Originally Called Bethania and Shattalon 100 kV Lines, RAS in November Solutions]	DEC	Underway	6/1/2027	0.8	TPL
E240197	Brunswick 1 - Delco 230 kV East Line (Brunswick 1 - Southport Tap), Upgrade Switch; Reconductor Brunswick 1-Southport Tap Section	DEP	Underway	6/1/2028	3.6	TPL
E220343	Goldsboro 115 kV Switching Station, Upgrade CT Ratio and Relay Settings on the Goldsboro-Womack 115 kV Line	DEP	Underway	6/1/2028	0.2	TPL
E240188	Brunswick 2 - Delco 230 kV West Line (Brunswick 2 - BEMC Southport), Raise Section	DEP	Underway	6/1/2028	1.9	TPL
W240008	Pinewood 100 kV Line, RAS (Grid Enhancing Technology) to Avoid Overloads on Pinewood Lines	DEC	Conceptual	TBD	0.1	TPL
W240295	Lookout Tie, RAS (Grid Enhancing Technology) to Avoid Overloads on Beulah and Hickory 100 kV Lines [Originally Called Beulah 100 kV Line, RAS in November Solutions]	DEC	Planned	12/1/2030	0.1	TPL
W240278	Central 230/100/44 kV Tie, Upgrade, Add Redundant Relaying	DEC	Planned	6/1/2031	0.7	TPL
W180359	States CTCC Bus Line 4, Construct	DEC	Planned	6/1/2031	3.8	TPL
W200592	Crest St 100 kV Lines, Raise Individual Towers	DEC	Planned	12/1/2031	2	TPL
W190390	Gastonia # 2 44 kV Line, Rebuild Clover 44kV Line to Double Circuit and Add a New Tap off the Gastonia #2 Line	DEC	Planned	6/1/2032	2.3	TPL
CTPCDEP04	Rocky Mount - Wilson 115 kV Line, Upgrade	DEP	Conceptual	TBD	TBD	TPL
W200425	Marshall 230 kV Line (Marshall-Beckerdite), Raise Individual Towers	DEC	Conceptual	TBD	0.2	TPL
W200588	Ferrell White 100 kV Line, Construct	DEC	Conceptual	TBD	0.7	TPL
W230387	E Durham 230/100 kV Tie, Construct Panther Line Terminals [Modification to 0096 in 2023 Plan - Split into Two Projects]	DEC	Conceptual	TBD	0.9	TPL

Project ID	Reliability Project (New to Plan <= \$5M)	Transmission Owner	Status ¹	Projected In-Service Date	Estimated Cost (\$M) ²	Initiating Study Type ⁴
W200168	Steam 100 kV Line (Dan River CC-Dan River Steam), Rebuild	DEC	Conceptual	TBD	1.1	TPL
W230093	Woodlawn 230/100/44 kV Tie Station, Upgrade Add 44 kV Breaker	DEC	Conceptual	TBD	1.8	TPL
W200170	Lakewood 100 kV Line (Lakewood-Remount Road Retail), Reconductor	DEC	Conceptual	TBD	2	TPL
W220474	Batts 100 kV Line (Concord-Winecoff), Reconductor	DEC	Conceptual	TBD	2.1	TPL
W210482	Madison Tie, Upgrade, Add 100/44 kV Transformer	DEC	Conceptual	TBD	2.4	TPL
W220543	Delta 100 kV Line (Research Triangle Retail-Ellis Rd Retail), Reconductor	DEC	Conceptual	TBD	3	TPL
W200146	Sweepsorville 100 kV Line (Mebane-Trollingwood Retail), Rebuild	DEC	Conceptual	TBD	3.4	TPL
Subtotal	Reliability Project (New to Plan <= \$5M)				\$52.2	
Reliability Projects Total					\$2,076.3	

¹ Status: *In-service*: Projects with this status are in-service. This status was updated as of 12/1/2024.

Underway: Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.

Planned: Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

Conceptual: Projects with this status are not planned at this time but will continue to be evaluated as a potential project in the future.

Deferred: Projects with this status were identified in the 2023 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2024 Collaborative Transmission Plan.

Removed: Project is cancelled and no longer in the plan

² The estimated cost is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

³ For projects with a status of Underway, the project lead time is the time remaining to complete construction and place in-service.

⁴ Initiating Study Type: *New Loads*: Econ Dev and Wholesale

PP: RZEP

TPL: BES (TPL) and non-BES Reliability

TSR: Transmission Service Request

AS: Affected System

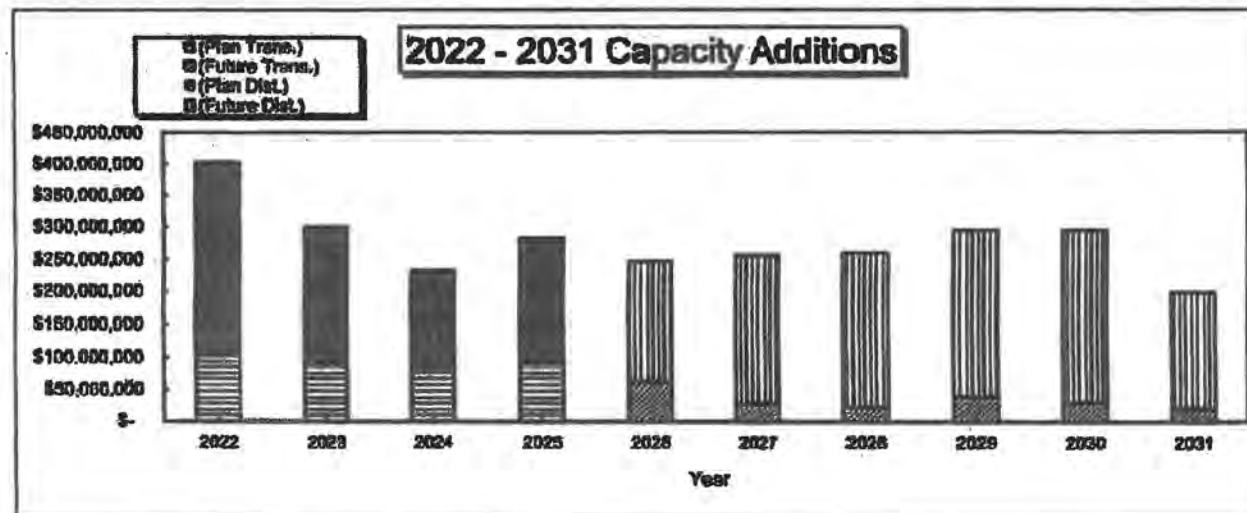
PUBLIC DISCLOSURE

2025 - 2034 T & D CAPACITY ADDITION EXPANSION PLAN

		NETWORK TRANSMISSION		LOAD SERVING DISTRIBUTION		TOTALS
		(Plan Trans.)	(Future Trans.)	(Plan Dist.)	(Future Dist.)	
1	2025	\$ 419,995,051		\$ 146,977,135		\$ 566,972,186
2	2026	\$ 623,126,504		\$ 252,011,693		\$ 875,138,197
3	2027	\$ 1,092,359,906		\$ 311,996,427		\$ 1,404,356,333
4	2028	\$ 1,518,597,793		\$ 324,134,863		\$ 1,842,732,656
5	2029	\$ 1,441,978,038		\$ 340,979,541		\$ 1,782,957,580
6	2030		\$ 1,492,447,270		\$ 352,913,825	\$ 1,845,361,095
7	2031		\$ 1,544,682,924		\$ 365,265,809	\$ 1,909,948,733
8	2032		\$ 1,598,746,826		\$ 378,050,112	\$ 1,976,796,939
9	2033		\$ 1,654,702,965		\$ 391,281,866	\$ 2,045,984,832
10	2034		\$ 1,712,617,569		\$ 404,976,732	\$ 2,117,594,301
Total		\$ 5,096,057,293	\$ 8,003,197,555	\$ 1,376,099,659	\$ 1,892,488,345	\$ 16,367,842,851

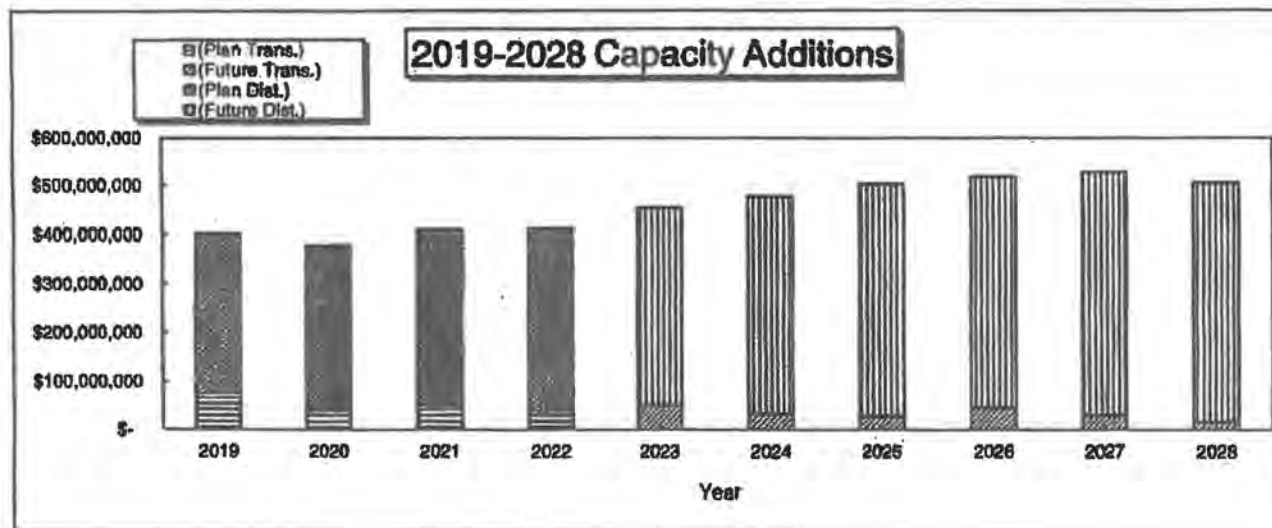
2022 - 2031 T & D CAPACITY ADDITION EXPANSION PLAN

		NETWORK TRANSMISSION		LOAD SERVING DISTRIBUTION		TOTALS
		(Plan Trans.)	(Future Trans.)	(Plan Dist.)	(Future Dist.)	
1	2022	\$ 103,018,676		\$ 300,103,172		\$ 403,121,848
2	2023	\$ 90,077,906		\$ 210,358,739		\$ 300,436,645
3	2024	\$ 78,455,319		\$ 153,686,775		\$ 232,142,094
4	2025	\$ 91,326,534		\$ 191,642,746		\$ 282,969,280
5	2026		\$ 62,772,213		\$ 183,809,275	\$ 246,581,488
6	2027		\$ 28,679,634		\$ 226,544,338	\$ 255,223,972
7	2028		\$ 23,459,897		\$ 235,615,058	\$ 259,074,955
8	2029		\$ 39,310,102		\$ 254,523,052	\$ 293,833,154
9	2030		\$ 29,903,889		\$ 263,838,233	\$ 293,742,122
10	2031		\$ 20,238,864		\$ 178,753,740	\$ 198,992,604
Total		\$ 362,878,435	\$ 204,384,600	\$ 855,791,432	\$1,343,083,695	\$2,786,118,162



POWER DELIVERY CAPACITY ADDITION EXPANSION PLAN
2019-2028

		NETWORK		LOAD SERVING		TOTALS
		TRANSMISSION		DISTRIBUTION		
		(Plan Trans.)	(Future Trans.)	(Plan Dist.)	(Future Dist.)	
1	2019	\$ 75,088,456		\$ 326,244,241		\$ 401,332,696
2	2020	\$ 39,912,449		\$ 337,208,113		\$ 377,120,562
3	2021	\$ 49,388,938		\$ 360,284,747		\$ 409,673,685
4	2022	\$ 38,360,558		\$ 373,371,778		\$ 411,732,335
5	2023		\$ 49,698,352		\$ 403,460,230	\$ 453,158,582
6	2024		\$ 31,461,448		\$ 445,342,741	\$ 476,804,189
7	2025		\$ 26,563,823		\$ 475,165,483	\$ 501,729,307
8	2026		\$ 43,593,866		\$ 472,690,172	\$ 516,284,038
9	2027		\$ 28,997,821		\$ 497,192,398	\$ 526,190,220
10	2028		\$ 16,128,940		\$ 488,318,325	\$ 504,447,265
		\$ 202,750,401	\$ 196,444,251	\$1,397,108,879	\$2,782,169,349	\$4,578,472,879



1 expects to procure?

2 A. (Witness Grubb) There was a lot there. So
3 let me hit a few of them. I would disagree with the
4 expansion plan not guiding the solar procurements. In the
5 '22 IRP and this IRP, that guidance of the amount we would
6 go procure in utility scale RFPs was driven by the
7 scenario of plans. It was an average across them. So
8 that's what we did in '22, and that's what we did in '25.

9 What the generic expansion plan is doing is
10 it's taking our estimates of the cost to build the
11 different technologies, and it's modeling that and picking
12 those. What it isn't doing is catching site specific
13 aspects of those units, and that's what the RFP does.
14 Whether it be generation-site specific, and that's when we
15 bring in the transmission.

16 So the expansion plan serves several roles.
17 One, is to give you an indication of what those
18 technologies are. It does not factor in transmission. We
19 do that in the RFPs. And then it also gives you the model
20 outputs to have an expected energy -- energy projections
21 for 20 to 30 years that we can do evaluations on. Without
22 that generic expansion build, you don't have enough
23 resources to meet your loads. So those are the reasons
24 for it.

25 And so what we've always said about the

EXHIBIT

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1 A. (Witness Grubb) And we also don't --

2 A. (Witness Hubbert) -- how they express it.

3 A. (Witness Grubb) What we're looking at is a
4 repeatable -- kind of a generic non-site specific number.
5 We're not sure if theirs are site-specific or, you know,
6 limited to a certain part of the state. We look at kind
7 of a Southern system generic type of costs to guide our
8 resource mix studies.

9 Q. We agree they're significantly higher
10 numbers? The numbers.

11 A. (Witness Hubbert) They are higher than what
12 we show in our mix study, yes.

13 Q. Are you aware that the price for a combined
14 cycle unit has significantly increased since the
15 assumptions you've provided in your filing?

16 A. (Witness Hubbert) We are aware of that. So
17 the vintage of the data that supported the mix study,
18 because it had to be done to support the filing, was
19 around August, maybe September time frame. So since that
20 time frame, we are aware that costs have increased because
21 of the global demand for combustion turbines, combined
22 cycles. But we did not update the mix study, including
23 higher costs. However, we have used a higher cost when
24 making offers to customers -- large load customers and
25 incorporating it into those analyses, but we didn't redo

EXHIBIT

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0210

1 battery system four times. And looking at the net present
2 value, we don't have to do an exhaustive analysis on
3 the -- what you would choose, on a battery system versus a
4 reconductor.

5 And just a reminder to the Commission, we
6 brought forward in this case 3300-megawatts of a portfolio
7 of projects as far as resources, but only \$60 million
8 worth of transmission. That is miniscule. That is \$18
9 per KW. And I think Mr. Bush would testify, as a
10 developer, that's not a lot of transmission at all. So I
11 think a lot of the intervenors treating it like it's a big
12 number. It's really not a big number. So we are bringing
13 forward very traditional solutions that we can make happen
14 in that period of time.

15 Now, if we study -- next year, we determine
16 that a Series Compensation device may be a better
17 solution, we will choose that. But in the meantime, as we
18 were doing studies for this, it made more sense to choose
19 the projects that we did. They were more economical, we
20 could get them done in the time frame, to get them done
21 for the units that we were proposing.

22 Q. So I'm still having a hard time now
23 reconciling the way you answered the question in the
24 prefiled versus the way you're answering it now, because
25 it's in the context of considering non-wires alternatives.



Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-GS Data Request Set No. 2

STF-GS-2-24

Question:

Please explain any changes in estimated costs from the 2022 ITS Ten-Year Plan to the 2024 ITS Ten-Year Plan for the following projects:

- a. GTC: Heard County – Tenaska 500kV (Second Line)
- b. SAV: CC - Big Ogeechee 500/230kV (CC Network Improvements)
- c. CC – QTS Fayetteville Transmission Needs
- d. SAV: McIntosh – Purrysburg 230kV Reactors
- e. Union City – Yates 230kV (Black) Line Rebuild

Response:

- a. The cost provided in the 2022 Georgia Integrated Transmission System (“ITS”) Ten-Year Plan was based on Planning Grade Estimates. The cost for each project is revised through scoping, engineering, and design processes, which include but are not limited to the increase in material costs over the years. The updated cost for all projects is provided annually through the Ten-Year Plan process.
- b. Please refer to the response to subpart (a) above.
- c. Please refer to the response to subpart (a).
- d. Please refer to the response to subpart (a).
- e. Please refer to the response to subpart (a).



Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-PIA Data Request Set No. 6

STF-PIA-6-21

Question:

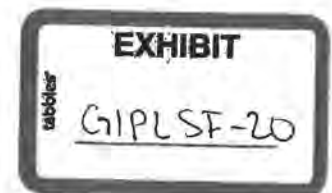
Please provide the present value of the total revenue requirements over the 12- year planning horizon for each of the four DSM cases.

Response:

The total revenue requirement associated with the programs in each of the four Demand Side Management ("DSM") cases is equivalent to the sum of the total budgeted Incentive Costs, Non-Incentive Costs, Cross-Cutting Costs, Evaluation Costs, and Additional Sum amounts. Please see the table below for the present value of the total revenue requirements over 2026-2037 for each of the four DSM cases.

Present Value (PV) Total Revenue Requirements in \$millions

	Proposed	Advocacy	Capacity & Affordability	Supply-Side
MG0	5,051	5,088	1,107	4,285
111-MG0	5,051	5,088	1,107	7,000



STF-BAI-1-1 Attachment Panel A

T&D Reliability and Resiliency	-	476
Economic Fleet Transition w/ Clean Energy	476	249
Environmental Compliance - CCR ARO	725	189
Technology - Customer Experience & Operations	914	98
State & Local Taxes	1,012	66
Incremental Inflation	1,078	94
Tax Reform Benefits Fully Utilized	1,172	220
ROE	1,392	94
Cost of Debt	1,375	111
Capital Structure	1,374	1
Non-Fuel O&M	1,212	163
Storm Cost Recovery	1,063	149
Sales Growth & Other	1,004	59
Levelized Rate Request		1,004



Waterfall

Revenue Requirement Drivers	Category	2023	2024	2025	Levelized		2023	2024	2025	Total
T&D Non-GRID Investments (Depreciation & Return)	T&D Reliability and Resiliency	\$ 134	\$ 272	\$ 385	\$ 258	T&D Reliability and Resiliency	\$ 476			\$ 476
T&D GRID Investments (Depreciation & Return)	T&D Reliability and Resiliency	80	168	245	161	Economic Fleet Transition w/ Clean Energy	225	27	(2)	249
New Depreciation Rates - T&D (Depreciation & Return)	T&D Reliability and Resiliency	57	58	58	58	Environmental Compliance - CCR ARO	64	78	47	189
Purchased Power	Economic Fleet Transition w/ Clean Energy	17	2	68	28	Technology - Customer Experience & Operations	98			98
Hydro/Solar/Other Incremental Capital (Depreciation & Return)	Economic Fleet Transition w/ Clean Energy	17	50	62	42	State & Local Taxes	62	2	1	66
New Depreciation Rates - Steam (Depreciation & Return)	Economic Fleet Transition w/ Clean Energy	138	128	125	130	Incremental Inflation	94			94
Tax Credits/Deductions	Economic Fleet Transition w/ Clean Energy	(15)	(19)	(24)	(19)	Tax Reform Benefits Fully Utilized	220			220
Wansley NBV Amortization	Economic Fleet Transition w/ Clean Energy	70	70	70	70	ROE	94			94
Wansley Existing Depreciation	Economic Fleet Transition w/ Clean Energy	(56)	(56)	(56)	(56)	Capital Structure	(1)			(1)
Intangible Investments (Depreciation & Return)	Technology - Customer Experience & Operations	34	78	137	81	Cost of Debt	(111)			(111)
Amortization - Customer Usage/Software and Cloud Computing	Technology - Customer Experience & Operations	10	10	10	10	Non-Fuel O&M	(163)			(163)
Electric Transportation (Capital and O&M)	Technology - Customer Experience & Operations	4	8	11	7	Storm Cost Recovery	(149)			(149)
Other Taxes (Non-Property)	State & Local Taxes	(18)	(17)	(15)	(17)	Sales Growth & Other	(59)			(59)
Other Taxes (Property)	State & Local Taxes	36	61	83	59	Total	\$ 852	\$ 107	\$ 45	\$ 1,004
O&M - Incremental Inflation	Incremental Inflation	67	75	80	74					
Capital - Incremental Inflation (Depreciation & Return)	Incremental Inflation	11	20	29	20	CCR ARO Annual Revenue Requirement	\$ 64	\$ 143	\$ 189	
Unprotected Excess Accumulated Deferred Income Taxes	Tax Reform Benefits Fully Utilized	220	220	220	220	CCR ARO Incremental Revenue Requirement	64	78	47	
O&M - Pension & Benefits	Non-Fuel O&M	(103)	(142)	(164)	(135)	DSM Annual Revenue Requirement	30	56	54	
Prepaid Pension Asset	Non-Fuel O&M	42	54	68	54	DSM Incremental Revenue Requirement	30	27	(2)	
O&M - Fleet Transition	Non-Fuel O&M	(55)	(84)	(100)	(79)	MFF Levelized Revenue Requirement	20	2	1	
O&M - Other	Non-Fuel O&M	(16)	(1)	48	9					
O&M - DSM (Non-Levelized)	Non-Fuel O&M	(13)	(13)	(10)	(12)					
O&M - Storm Damage Accrual	Storm Cost Recovery	(149)	(149)	(149)	(149)					
New Depreciation Rates - Other (Depreciation & Return)	Sales Growth & Other	78	76	71	75					
Amortization - Other	Sales Growth & Other	(22)	(29)	(44)	(31)					
Base Revenues	Sales Growth & Other	(86)	(72)	(73)	(77)					
Other Revenues	Sales Growth & Other	2	(19)	(29)	(15)					
Other	Sales Growth & Other	32	(27)	(43)	(11)					
Capital Structure	Capital Structure	(1)	(1)	(1)	(1)					
ROE	ROE	94	94	94	94					
Cost of Debt	Cost of Debt	(118)	(112)	(102)	(111)					
Total		\$ 490	\$ 706	\$ 1,056	\$ 737					

Reg. Assets/Liabilities	439,036	590,639	1,029,675	40,583	1,070,258	68,115	1,138,373
AROs	(2,103,216)	334,095	(1,769,121)	42,404	(1,726,717)	42,404	(1,684,312)
ARO Reg Liability (254)	228,906	61,685	290,591	74,563	365,154	115,491	480,645
Other Rate Base Items	-	-	-	-	-	-	-
Accumulated Deferred Income Taxes	(5,983,437)	(524,658)	(6,508,095)	(160,443)	(6,668,537)	(150,288)	(6,818,826)
Total Rate Base	22,418,319	2,550,292	24,968,611	1,878,432	26,847,043	1,601,591	28,448,634
Weighted Average Cost of Capital	7.91%		7.71%		7.74%		7.77%
Return on Rate Base	1,772,409	153,521	1,925,931	150,796	2,076,727	133,986	2,210,714
Expenses:							
Production Fixed & Variable	706,834	(59,752)	647,082	(34,211)	612,870	326	613,196
System Control & Load Dispatching	36,029	(245)	35,784	1,699	37,484	2,028	39,512
Transmission	128,102	(10,076)	118,026	4,283	122,309	6,540	128,849
Distribution	289,039	29,255	318,294	9,400	327,694	11,922	339,616
Customer Accounting	164,430	23,747	188,178	7,290	195,468	4,052	199,520
Customer Assistance	104,168	8,684	112,852	1,129	113,980	(707)	113,273
DSM Additional Sum	14,985	2,226	17,212	27	17,239	20	17,259
PPA Additional Sum	21,882	(1,852)	20,029	3,312	23,341	12,592	35,933
Energy Services	51,037	(18,459)	32,578	932	33,510	1,486	34,996
Administrative & General	271,375	(77,432)	193,943	(33,684)	160,260	(11,151)	149,108
Storm Damage Accrual	213,328	(148,525)	64,803	-	64,803	-	64,803
Interest on Customer Deposits	8,965	(1,173)	7,793	75	7,868	76	7,944
Total O&M	2,010,175	(253,600)	1,756,574	(39,749)	1,716,826	27,183	1,744,009
Purchased Power	261,311	19,279	280,590	(18,369)	262,221	53,376	315,597
Fuel	2,476,738	(232,901)	2,243,837	(53,035)	2,190,802	60,693	2,251,494
Depreciation	1,161,197	289,458	1,450,655	113,603	1,564,258	114,443	1,678,702
ARO	182,787	71,371	254,158	71,113	325,271	36,838	362,109
Amortization	66,159	(12,451)	53,708	(6,286)	47,421	(14,871)	32,550
Amortization - Wansley	-	69,677	69,677	(2)	69,675	-	69,675
Other Taxes (Non Property Related)	54,505	(17,977)	36,528	1,329	37,857	1,575	39,432
Other Taxes (MFF & Property Related)	240,355	35,706	276,060	24,861	300,921	22,468	323,390
Income Taxes	167,646	131,454	299,100	(46,401)	252,699	(71,392)	181,307
Total Expenses	6,620,873	100,015	6,720,888	47,064	6,767,952	230,312	6,998,264
Total Revenue Requirement	8,393,283	253,536	8,646,819	197,861	8,844,680	364,298	9,208,978

Cost of Capital					
2023					
Component	Proportion	Cost	Component	RR Rate	Debt/Equity
Long-Term Debt	44.00%	3.53%	1.55%	1.55%	1.55%
Common Equity	56.00%	11.00%	6.16%	8.25%	8.25%
TOTAL	100.00%		7.71%	9.80%	9.80%
2024					
Component	Proportion	Cost	Component	RR Rate	Debt/Equity
Long-Term Debt	44.00%	3.58%	1.58%	1.58%	1.58%
Common Equity	56.00%	11.00%	6.16%	8.25%	8.25%
TOTAL	100.00%		7.74%	9.82%	9.82%
2025					
Component	Proportion	Cost	Component	RR Rate	Debt/Equity
Long-Term Debt	44.00%	3.66%	1.61%	1.61%	1.61%
Common Equity	56.00%	11.00%	6.16%	8.25%	8.25%
TOTAL	100.00%		7.77%	9.86%	9.86%
Current Weighted Average					
Component	Proportion	Cost	Component	RR Rate	Debt/Equity
Long-Term Debt	43.97%	4.60%	2.02%	2.02%	2.02%
Common Equity	56.03%	10.50%	5.88%	7.87%	7.87%
TOTAL	100.00%		7.91%	9.90%	9.90%
2023 with Cap Cost of Current					
Component	Proportion	Cost (Current)	Component	RR Rate	Debt/Equity
Long-Term Debt	44.00%	4.60%	2.02%	2.02%	2.02%
Common Equity	56.00%	10.50%	5.88%	7.87%	7.87%
TOTAL	100.00%		7.90%	9.90%	9.90%

T&D (Non-GRID)											
(Amounts in Thousands)											
	Current	2023	Net		Current	2024	Net		Current	2025	Net
Transmission											
Rate Base											
PIS	\$ 7,313,400	\$ 7,929,033			\$ 7,313,400	\$ 8,734,015			\$ 7,313,400	\$ 9,379,236	
Acc Res	(1,464,675)	(1,402,083)			(1,464,675)	(1,405,726)			(1,464,675)	(1,450,230)	
ADITs	(1,305,892)	(1,366,737)			(1,305,892)	(1,441,988)			(1,305,892)	(1,502,556)	
Net Rate Base	\$ 4,542,833	\$ 5,160,214			\$ 4,542,833	\$ 5,886,301			\$ 4,542,833	\$ 6,426,450	
Cost of Capital	9.90%	9.90%			9.90%	9.90%			9.90%	9.90%	
Return	\$ 449,653	\$ 510,762	\$ 61,109		\$ 449,653	\$ 582,631	\$ 132,978		\$ 449,653	\$ 636,095	\$ 186,442
Income											
Depreciation	\$ 155,975	\$ 196,649	\$ 40,674		\$ 155,975	\$ 217,439	\$ 61,464		\$ 155,975	\$ 233,638	\$ 77,662
Total Revenue Requirement	\$ 605,629	\$ 707,412	\$ 101,783		\$ 605,629	\$ 800,070	\$ 194,441		\$ 605,629	\$ 869,733	\$ 264,104
Distribution											
Rate Base											
PIS	\$ 13,242,586	\$ 14,253,996			\$ 13,242,586	\$ 15,474,036			\$ 13,242,586	\$ 16,620,127	
Acc Res	(3,835,725)	(3,529,253)			(3,835,725)	(3,666,425)			(3,835,725)	(3,842,801)	
ADITs	(1,778,321)	(1,921,307)			(1,778,321)	(1,972,991)			(1,778,321)	(2,029,669)	
Net Rate Base	\$ 7,628,541	\$ 8,803,437			\$ 7,628,541	\$ 9,834,621			\$ 7,628,541	\$ 10,747,656	
Cost of Capital	9.90%	9.90%			9.90%	9.90%			9.90%	9.90%	
Return	\$ 755,079	\$ 871,371	\$ 116,292		\$ 755,079	\$ 973,439	\$ 218,360		\$ 755,079	\$ 1,063,812	\$ 308,733
Income											
Depreciation	\$ 359,519	\$ 414,038	\$ 54,520		\$ 359,519	\$ 450,377	\$ 90,859		\$ 359,519	\$ 484,141	\$ 124,622
Total Revenue Requirement	\$ 1,114,598	\$ 1,285,410	\$ 170,812		\$ 1,114,598	\$ 1,423,816	\$ 309,218		\$ 1,114,598	\$ 1,547,953	\$ 433,355
Total Transmission & Distribution											
Total Revenue Requirement	\$ 1,720,227	\$ 1,992,821	\$ 272,595		\$ 1,720,227	\$ 2,223,886	\$ 503,659		\$ 1,720,227	\$ 2,417,686	\$ 697,459
Depreciation - New Rates		(56,581)				(57,915)				(58,217)	
Subtotal	\$ 1,720,227	\$ 1,936,240	\$ 216,013		\$ 1,720,227	\$ 2,165,971	\$ 445,744		\$ 1,720,227	\$ 2,359,469	\$ 639,242
GRID			(79,695)				(168,107)				(245,474)
Subtotal			\$ 136,319				\$ 277,638				\$ 393,768

2023 IRP Update - Estimated Net Impacts to Customers

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load projects.

Values stated in millions of dollars and rounded to nearest ten million. Estimates are subject to change. Fuel costs and revenues not included in estimated incremental revenue requirements and estimates.

**Reflects projected transmission capital associated with Plant Yates Units 8-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026.*

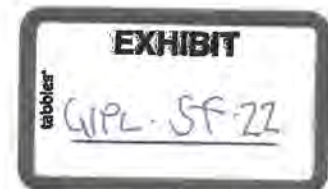
***Estimated revenues based on 2023 IRP Update external adjustments for won and potential large load projects.*

Cumulative View

	2026	2027	2028
Estimated Incremental Revenue Requirement due to Load Growth*	\$190	\$580	\$620
Estimated Incremental Revenue due to Load Growth**	\$340	\$680	\$860
Net Estimated Cumulative Impact to Customers	-\$150	-\$100	-\$240

Incremental View

	2026	2027	2028
Total Revenues	\$10,970	\$10,660	\$10,760
Estimated Incremental Revenue Requirement due to Load Growth*	\$190	\$390	\$40
Estimated Incremental Revenue due to Load Growth**	\$340	\$340	\$190
Net Estimated Incremental Impact to Customers	-\$150	\$50	-\$150
Estimated Rate Impact (%)	-1.4%	0.5%	-1.4%
Cumulative (compounded) %	-1.4%	-0.9%	-2.3%
Estimated Typical Residential \$/month Impact	-\$2.58	\$0.86	-\$2.58
Cumulative Typical Residential \$/month Impact	-\$2.58	-\$1.72	-\$4.30



2023 IRP Update - Estimated Incremental Revenue Requirements for Net Deferred Costs of PPAs

Values stated in millions of dollars. Estimates are subject to change. Fuel costs not included in estimated incremental revenue requirements.

Estimates do not include revenues from any future remarketing of remaining PPA capacity which will further offset the net deferred costs.

	2024	2025	2026	2027	2028
Mississippi Power PPA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Regional Sale PPA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Santa Rosa PPA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Amount Deferred	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Reg Asset Beginning Balance	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Amortization	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Reg Asset Ending Balance	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Deferred Tax Liability	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Average	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Pre-Tax Weighted Average Cost of Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Financing Cost on Reg Asset	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Total Revenues

Values stated in millions of dollars. Estimates are subject to change.

	2026	2027	2028
Budget 2023 Total non-fuel Revenues	\$8,077	\$8,124	\$8,195
Fuel (FCR26 settlement budget)	\$2,889	\$2,540	\$2,562
Total Revenues	\$10,966	\$10,664	\$10,757
Net Incremental Revenue Requirement	-\$150	\$50	-\$150
Grossed up for MFF impact	-\$154	\$51	-\$154

GEORGIA POWER COMPANY
COMPUTATION OF RETAIL REVENUE DEFICIENCY
APPLICABLE TO BASE RATE TARIFFS
FOR THE TWELVE MONTH PERIODS ENDING JULY 31, 2023 AND DECEMBER 31, 2023-2025
(AMOUNTS IN THOUSANDS)

Line No.	Description	Test Period	2023	2024	2025	
(1)	(2)	(3)	(4)	(5)	(6)	
1	Retail Rate Base	\$ 24,018,127	\$ 24,968,611	\$ 26,847,043	\$ 28,448,634	(a)
2	Requested Rate of Return	> 7.70%	7.71%	7.74%	7.77%	(b)
3	Earnings Requirement	\$ 1,849,696	\$ 1,925,931	\$ 2,076,727	\$ 2,210,714	
4	Less: Earnings Available for Return	- 1,515,820	1,490,104	1,401,302	1,241,726	(c)
5	Earnings Deficiency	\$ 333,876	\$ 435,827	\$ 675,426	\$ 968,987	
6	Income Expansion Factor	÷ 74.606%	74.602%	74.596%	74.593%	(d)
7	Total Revenue Deficiency Excluding MFF	\$ 447,521	\$ 584,204	\$ 905,447	\$ 1,299,024	

Note: Details may not add to totals due to rounding.

- (a) From Exhibit (APA/SPA/ADH/MBR-1, Schedule 1 Total Company) Pages 3, 5, 7, and 9 for Test Period, 2023, 2024, and 2025, respectively
(b) From Exhibit (APA/SPA/ADH/MBR-3, Schedule 2, Workpapers 1-4) for Test Period, 2023, 2024, and 2025, respectively
(c) From Exhibit (APA/SPA/ADH/MBR-1, Schedule 1 Total Company) Pages 4, 6, 8, and 10 for Test Period, 2023, 2024, and 2025, respectively
(d) From Exhibit (APA/SPA/ADH/MBR-1, Schedule 1 Total Company) Page 2

EXHIBIT

tabbles

6/PL-JF-23

0223



Q1 2025 Large Load Economic Development Report

May 22, 2025

Docket No. 55378



<u>Class</u>	<u>Segment</u>	<u>Territory</u>	<u>Project Stage</u>	<u>Announced Load*</u>
Commercial	Data Center	Inside	Technical Review	1,680
Commercial	Data Center	Outside	Contract for Electric Service ¹	1,429
Commercial	Data Center	Inside	Technical Review	1,200
Commercial	Data Center	Inside	Technical Review	1,200
Commercial	Data Center	Inside	Technical Review	1,200
Commercial	Data Center	Inside	Technical Review	1,200
Commercial	Data Center	Inside	Technical Review	1,200
Commercial	Data Center	Inside	Technical Review	1,200
Commercial	Data Center	Inside	Technical Review	1,186
Commercial	Data Center	Inside	Technical Review	1,150
Industrial	Manufacturing	Multiple Sites	Technical Review	1,020
Commercial	Data Center	Inside	Technical Review	1,000
Commercial	Data Center	Inside	Technical Review	1,000
Commercial	Data Center	Inside	Technical Review	910
Commercial	Data Center	Inside	Technical Review	910
Commercial	Data Center	Inside	Technical Review	910
Commercial	Data Center	Inside	Request for Service	901
Commercial	Data Center	Inside	Technical Review	800
Commercial	Data Center	Inside	Technical Review	780
Commercial	Data Center	Inside	Technical Review	750
Commercial	Data Center	Inside	Technical Review	750
Commercial	Data Center	Inside	Technical Review	750
Commercial	Data Center	Inside	Technical Review	750
Commercial	Data Center	Inside	Technical Review	725
Commercial	Data Center	Inside	Request for Service	693
Commercial	Data Center	Inside	Technical Review	656
Commercial	Data Center	Inside	Technical Review	651
Commercial	Data Center	Inside	Technical Review	650
Commercial	Data Center	Inside	Technical Review	648
Commercial	Data Center	Inside	Technical Review	600

<u>2033</u>	<u>2034</u>	<u>2035</u>	<u>2036</u>	<u>2037</u>	<u>New Project?</u>	<u>Change in Announced Load</u>	<u>Load Ramp</u>	<u>Project Stage</u>	<u>Initial Service Date</u>
1,056	1,200	1,368	1,476	1,680					Y
1,429	1,429	1,429	1,429	1,429			Y.		
1,200	1,200	1,200	1,200	1,200					Y
1,200	1,200	1,200	1,200	1,200	Y				
1,200	1,200	1,200	1,200	1,200					Y
1,200	1,200	1,200	1,200	1,200	Y				
1,200	1,200	1,200	1,200	1,200			Y		Y
1,200	1,200	1,200	1,200	1,200	Y				
1,186	1,186	1,186	1,186	1,186					Y
1,150	1,150	1,150	1,150	1,150	Y				
1,020	1,020	1,020	1,020	1,020					
1,000	1,000	1,000	1,000	1,000					
1,000	1,000	1,000	1,000	1,000					Y
910	910	910	910	910					
910	910	910	910	910		Y	Y		
910	910	910	910	910					
901	901	901	901	901					
800	800	800	800	800	Y				
780	780	780	780	780		Y	Y		Y
750	750	750	750	750	Y				
750	750	750	750	750					Y
750	750	750	750	750	Y				
750	750	750	750	750					Y
725	725	725	725	725					
693	693	693	693	693			Y		
503	536	581	623	656					Y
642	651	651	651	651					Y
527	583	650	650	650					Y
648	648	648	648	648					
600	600	600	600	600					Y

1 provides additional reliability to the area, which has seen limited growth in
2 generation development.

3
4 Finally, the Yates CTs will support the continued integration and penetration of
5 renewables and storage on the electric System. Notably, the Company's correction
6 of PIA Staff's expansion plans resulted in the selection of Yates 8 in winter 2027
7 and Yates 9-10 in winter 2028 as the Company proposed.

8 **Q. PLEASE RESPOND TO THE ASSERTIONS MADE BY INTERVENORS**
9 **THAT THE COMPANY DOES NOT NEED ALL THREE OF THE YATES**
10 **CTS IF TRANSMISSION RESTRICTS THE OUTPUT OF THE PLANT**
11 **DURING PEAK PERIODS WITH TRANSMISSION CONTINGENCIES?**

12 A. There is only one specific transmission case where the full output of the three units
13 was restricted. In all other scenarios, once online, all three units will be available to
14 be economically dispatched. It is more economical to build three units
15 consecutively to take advantage of economies of scale, especially when the
16 expansion plan indicates a need for CTs to meet future needs. Additionally, the
17 three CTs will be the most efficient CTs on the Southern Company System, which
18 enables all three units to be dispatched ahead of other CTs and the Yates 6-7 steam
19 units.

20 **Q. WHY SHOULD THE COMMISSION HAVE CONFIDENCE IN THE**
21 **ECONOMICS OF THE PROPOSED YATES UNITS?**

22 A. Even though the proposed Yates units are being procured outside the typical RFP
23 process, the Commission can have confidence in the economics of Plant Yates
24 Units 8-10. The Company routinely engages with established original equipment
25 manufacturers ("OEMs") and engineering, procurement, and construction ("EPC")
26 firms to evaluate the costs and risks associated with projects like those proposed at
27 Plant Yates. The expertise garnered from these engagements ensures a high level

1 did not, because we don't have time to run an RFP. But
2 that doesn't mean we're not confident in the costs.

3 Q. Okay. So let's look at that cost. You
4 provide basically two pieces of evidence to support your
5 conclusion that it's cost effective, or that the company
6 should have confidence in it being cost effective. One of
7 those is Attachment D to the Yates certification
8 application; correct?

9 A. (Witness Bush) That's correct.

10 Q. And in that attachment, and I understand
11 you've updated with more recent numbers, but in that
12 attachment, Georgia Power chose three projects to compare;
13 correct?

14 A. (Witness Bush) Well, actually, Commissioners,
15 there's no publicly available data, that is a general
16 location, where you can go find this type of information.
17 So this is actually what we found at the time, when we
18 certified, actually.

19 Since then, we've found one other publicly
20 available set of information around CTs of this nature.
21 And, again, we're talking about advance-class CTs, that
22 have state-of-the-art emission controls. And so when you
23 make comparisons of this type, you have to make sure
24 you're making them with the right technology, and then you
25 have to equalize, or normalize, for the period of going in

1 number is higher, generally speaking, I would say they're
2 all within a similar range of costs.

3 Q. The second piece of evidence that you refer
4 to is Lazard's 2023 levelized cost of energy analysis,
5 which I believe is an exhibit to your testimony,
6 Exhibit 3.

7 A. (Witness Grubb) That's right.

8 A. (Witness Bush) That's correct.

9 Q. And am I correct that, in this exhibit, the
10 place to look is the gas peaking row, because these are
11 CTs?

12 A. (Witness Bush) That's correct. The Lazard
13 report is generally a levelized cost of energy. And when
14 you compare technologies, we would say that's not how you
15 want to do that. But in the report itself, it does have
16 a -- an exhibit itself that talks about the capital
17 cost -- what they call overnight capital costs for
18 different technologies. And what we've done in this
19 exhibit is, we've pulled out the capital costs for a
20 similar technology.

21 Again, if you look at the numbers themselves
22 and the information behind that technology, there's no
23 indication -- first of all, what year dollars these
24 overnight costs are in, and that's important when making
25 the comparison, nor is there the specifics behind the

EXHIBIT 2 – Revised TS Attachment D to the Yates Certification Application

Comparison of Advanced Frame Simple-Cycle Combustion Turbine Projects - Amended Canal 3 and Grand River 2024 \$ Cost (In red)

Project	Plant Yates CT Units 8, 9, & 10*	Canal 3 (ref 1,2,3)***	Grand River Dam Authority (ref 4,5)****
Plant Capacity (MW)	1,325	350	420
Reported Completion Cost (k\$)	REDACTED	\$280,000	\$410,000
Actual Project Cost (\$/kW)	REDACTED	\$800	\$976
Reported Completion Cost (2024 k\$)**	REDACTED	\$336,375	REDACTED
Current Project Cost (2024\$/kW)**	REDACTED	\$961	REDACTED
Location	Newnan, GA	Sandwich, MA	Chouteau, OK
Site	Existing	Existing	Existing
Owner	Georgia Power Company	Stonepeak Infrastructure Partners	Grand River Dam Authority
EPC Contractor	Black and Veatch/Mitsubishi	Burns & McDonnell/Skanska USA Civil	Unknown
Commercial Operation	12/1/2026, 5/1/2027, 8/1/2027	June-2019	April-2026
Configuration	Simple Cycle CT	Simple Cycle CT	Simple Cycle CT
Turbine Technology	Mitsubishi MS01 JAC	GE 7HA.02	Mitsubishi MS01 JAC
Fuel Type	NG/ULSD	NG/ULSD	NG/Unknown
Emissions Control	Hot SCR	Hot SCR	Unknown

*Yates CT cost of gas lateral and financing excluded for comparison

**Values adjusted using escalation of REDACTED

***Amended values for Canal 3 based on GDP Price Deflator | U.S. Bureau of Economic Analysis (BEA) (<https://www.bea.gov/data/prices-inflation/gdp-price-deflator>)

****Amended values for Grand River to assume published cost is in nominal 2025\$

References

- <https://gasturbine-world.com/simple-cycle-350-mw-7ha-02-peaking-plant/>
- <https://www.nrgenergybusiness.com/news/burns-mcdonnell-canal-3-power-plant/>
- <https://www.power-eng.com/gas/gas-and-diesel-fired-canal-3-station-completed-at-cape-cod/#gref>
- <https://power.mhi.com/regions/amer/news/100323>
- <https://www.readfrontier.org/stories/grand-river-dam-authority-looks-to-replace-its-last-coal-fired-generator-with-a-new-410-million-project/#:~:text=The%20Grand%20River%20Dam%20Authority,River%20Energy%20Center%20in%20Choteau>

Rebuttal Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush
On behalf of Georgia Power Company
Docket No. 55378
Exhibit 2 - Page 1

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549**

FORM 8-K

**CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934**

Date of Report (Date of earliest event reported): June 4, 2025

Oglethorpe Power Corporation

(An Electric Membership Corporation)

(Exact name of Registrant as specified in its charter)

Georgia
(State of incorporation)

333-192954
(Commission File Number)

58-1211925
(I.R.S. Employer
Identification No.)

**2100 East Exchange Place
Tucker, Georgia**
(Address of principal executive offices)

30084-5336
(Zip Code)

Registrant's telephone number, including area code **(770) 270-7600**

None

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

- ☐ [] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ [] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ [] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ [] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter)

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Securities registered pursuant to section 12(b) of the Act:

Title of each class:	Trading Symbol(s)	Name of each exchange on which registered:
None	N/A	N/A



SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

OGLETHORPE POWER CORPORATION
(AN ELECTRIC MEMBERSHIP CORPORATION)

Date: June 4, 2025

By: /s/ Annalisa M. Bloodworth
Annalisa M. Bloodworth
President and Chief Executive Officer

Notice to Recipients

Certain of the information contained in this presentation, including certain of the statements made by representatives of Oglethorpe Power Corporation (An Electric Membership Corporation) ("Oglethorpe" or "OPC"), that are not historical facts are forward-looking statements. Although Oglethorpe believes that in making these forward-looking statements its expectations are based on reasonable assumptions, Oglethorpe cautions the reader not to put undue reliance on these forward-looking statements, which are not guarantees of future performance. Forward-looking statements involve uncertainties and there are important factors, many of which are outside management's control, which could cause actual results to differ materially from those expressed or implied by these forward-looking statements. Some of the risks, uncertainties and assumptions that may cause actual results to differ from these forward-looking statements are described under the headings "CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION" in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2025, filed with the Securities and Exchange Commission on May 14, 2025, and "ITEM 1A - RISK FACTORS" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2024, filed with the Securities and Exchange Commission on March 31, 2025.

This electronic presentation is provided as of June 4, 2025. If you are viewing this presentation after that date, there may have been events that occurred subsequent to such date that could have a material adverse effect on the information that was presented.

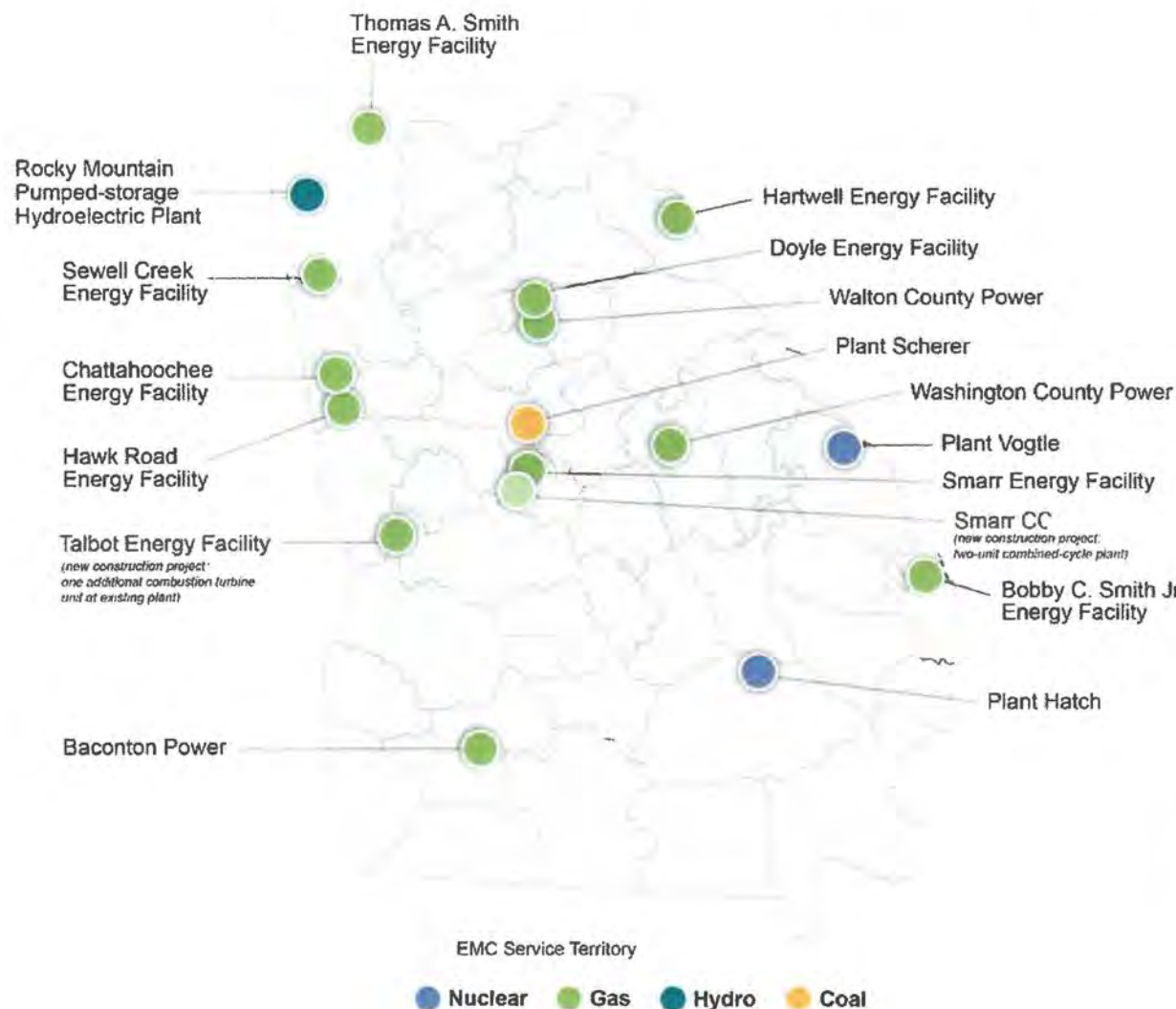
Oglethorpe undertakes no obligation to publicly update any forward-looking statements.

Smarr Combined Cycle Project – Update

Smarr CC (1,425 MW, two-unit combined cycle; 2029 projected in-service date)

- Selected GE Vernova as original equipment manufacturer.
 - GE Vernova will supply two of its high-efficiency 7HA.03 gas turbines, two H84 hydrogen-cooled generators, two triple-pressure with reheat Heat Recovery Steam Generators and two STF-D600 steam turbines with H65 hydrogen-cooled generators.
 - Oglethorpe has GE units in its fleet and has worked with GE Vernova for many years to maintain and enhance the performance of these turbines.
- Preliminary cost estimate for this facility is \$1.8 to \$2.3 billion, and we are actively refining this estimate amid ongoing market volatility.
 - We anticipate finalizing our budget by late summer following the completion of our RFP process for engineering, procurement and construction services.

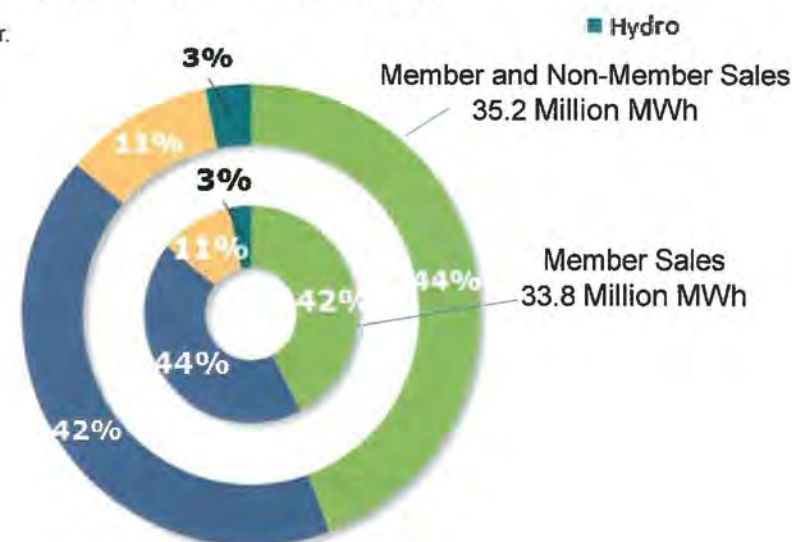
Oglethorpe's Diversified Power Supply Portfolio



2025 Capacity (MW)
9,323 MW (a)

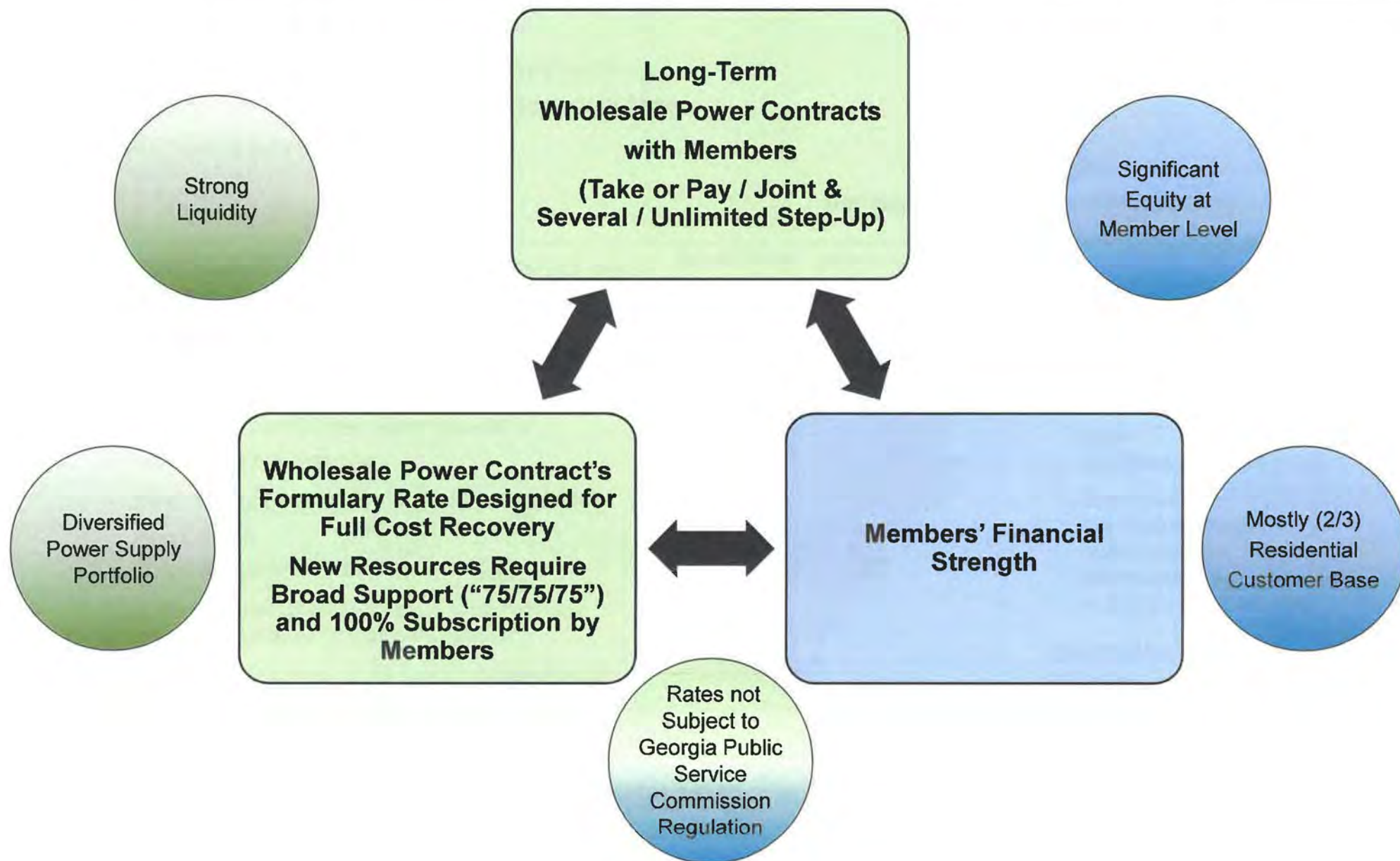


2025 Energy (MWh)
(April 2024 – March 2025)



(a) Capacity and energy include Oglethorpe and Smarr EMC resources. Oglethorpe and Smarr EMC capacity reflects summer reserve planning capacity.

Cornerstones of Oglethorpe's Credit Strength: Contracts, Rate Structure and Members



Financial Strength of Oglethorpe's Members

Member 2024 Average Financial Ratios

TIER:
3.55x

Equity/Assets:
41%

Equity/Total Capitalization:
50%

Members' 2024 Aggregate Financial Metrics

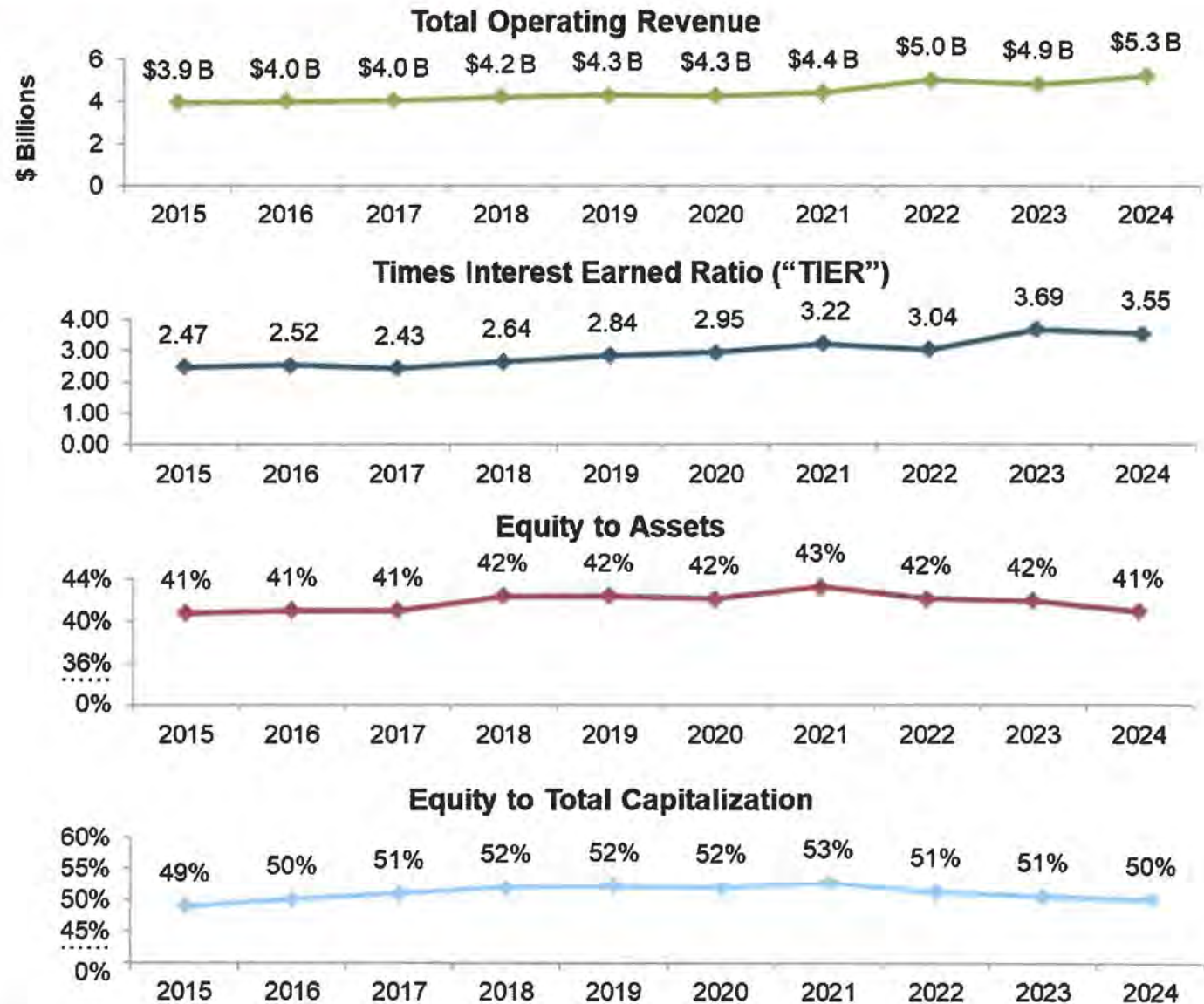
Total Annual Revenues:
\$5.3 billion

Total Net Margins:
\$513 million

Total Patronage Capital:
\$5.3 billion

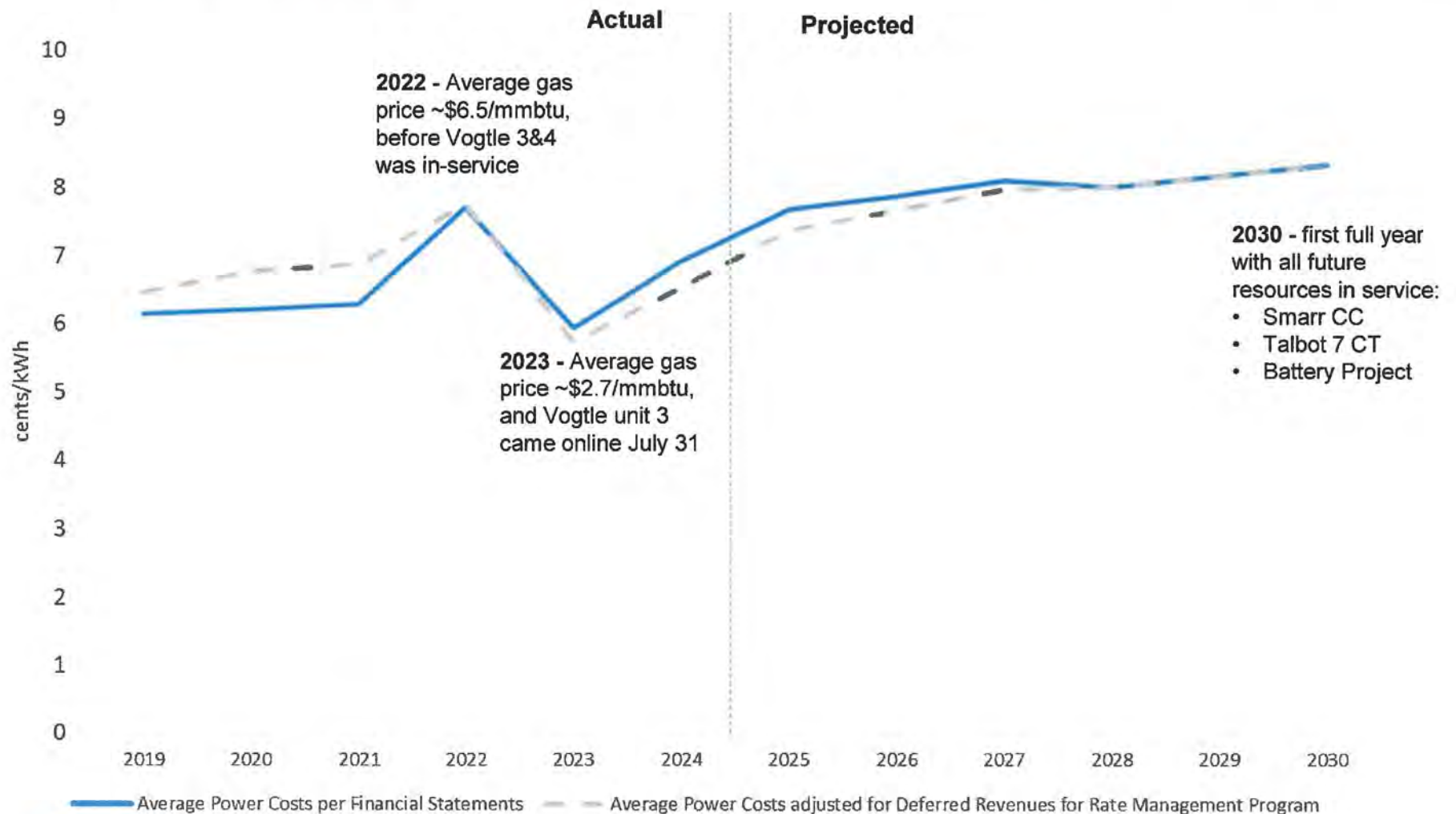
Total Assets:
\$13.0 billion

Note: Oglethorpe's debt is not the direct obligation of the Members and, as a result, the capital of the Members does not directly support the principal and interest payments to be made by Oglethorpe on its outstanding indebtedness.



Note: 2024 figures are preliminary estimates based on 37 of 38 Members reporting year-end financial data to-date.

Historical & Projected Wholesale Power Cost



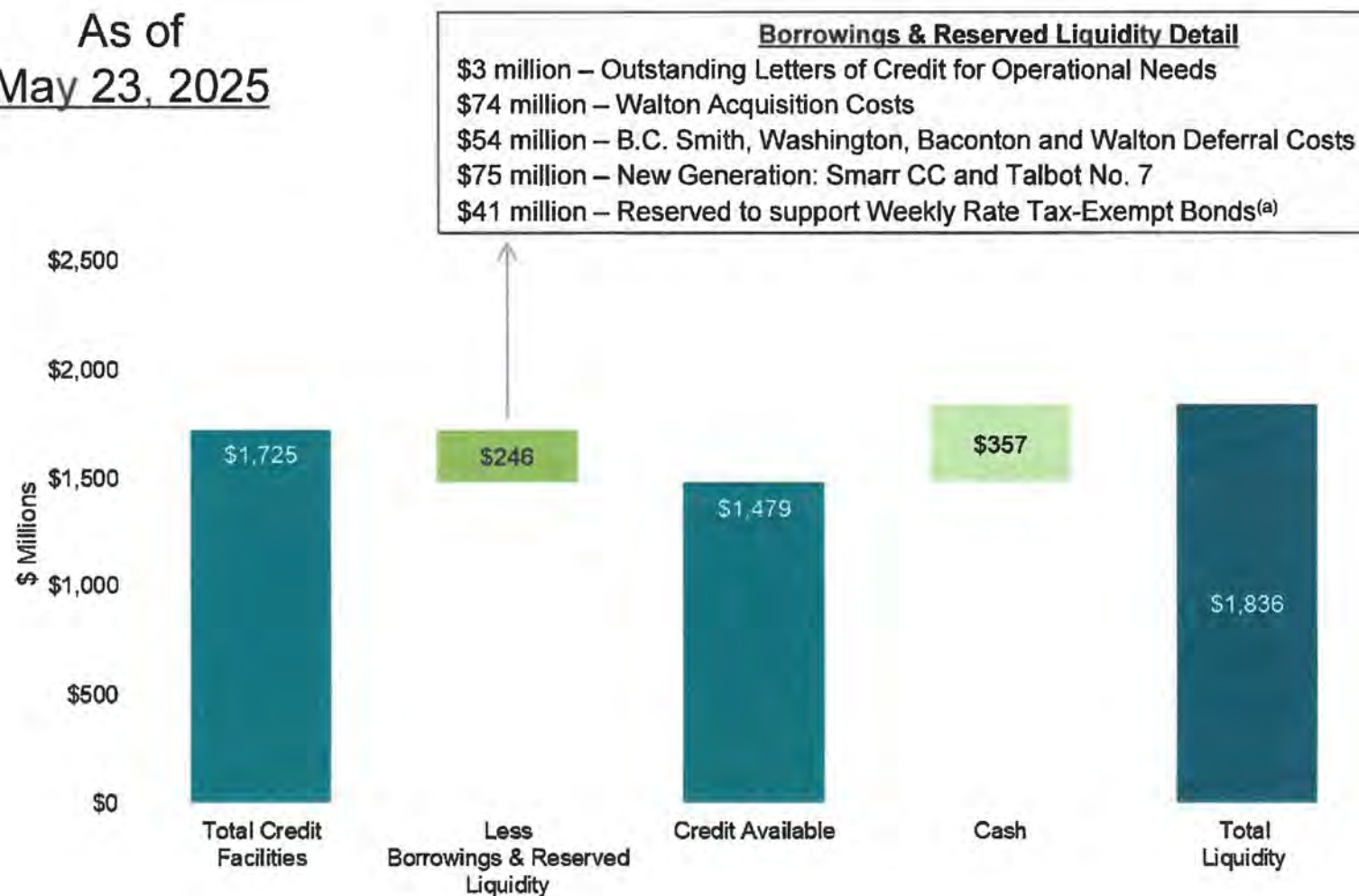
Balance Sheet Excerpts

(\$ in thousands)	March 31,	December 31,	
	2025	2024	2023
Balance Sheet Data:			
Assets:			
Electric Plant:			
Net Plant in Service	\$11,926,488	\$11,989,581	\$8,996,092
CWIP	456,401	320,167	3,294,641
Nuclear Fuel	415,114	402,328	389,662
Total Electric Plant	\$12,798,003	\$12,712,076	\$12,680,395
Total Investments and Funds	1,486,384	1,492,372	1,449,689
Total Current Assets	1,036,898	1,109,969	1,191,687
Total Deferred Charges	1,174,194	1,163,121	1,203,080
Total Assets	\$16,495,479	\$16,477,538	\$16,524,851
Capitalization:			
Patronage Capital and Membership Fees	\$1,371,424	\$1,328,418	\$1,257,917
Long-term Debt and Finance Leases	12,170,334	12,167,367	11,644,503
Other	37,690	37,625	35,014
Total Capitalization	\$13,579,448	\$13,533,410	\$12,937,434
Total Current Liabilities	905,756	936,414	1,358,453
Total Deferred Credits and Other Liabilities	2,010,275	2,007,714	2,228,964
Total Equity and Liabilities	\$16,495,479	\$16,477,538	\$16,524,851
Total Capitalization	\$13,579,448	\$13,533,410	\$12,937,434
Plus: Unamortized Debt Issuance Costs and Bond Discounts on LT debt	123,997	120,328	120,560
Plus: Long-term Debt and Finance Leases due within one year	395,130	398,979	384,426
Total Long-Term Debt and Equities	\$14,098,575	\$14,052,717	\$13,442,420
Equity Ratio^(a)	9.7%	9.5%	9.4%

^(a) The equity ratio is calculated, pursuant to Oglethorpe's First Mortgage Indenture, by dividing patronage capital and membership fees by total capitalization plus unamortized debt issuance costs and bond discounts and long-term debt due within one year (Total Long-Term Debt and Equities in the table above). Oglethorpe has no financial covenant requirement to maintain a minimum equity ratio; however, a covenant in the Indenture restricts distributions of equity (patronage capital) to its Members if its equity ratio is below 20%. Oglethorpe also has covenants in three credit agreements that require a minimum total patronage capital, with the highest such requirement being \$900 million. The equity ratio is less than that of many investor-owned utilities because Oglethorpe operates on a not-for-profit basis and has a significant amount of authority to set and change rates to ensure sufficient cost recovery to produce margins to meet financial coverage requirements.

Oglethorpe's Available Liquidity

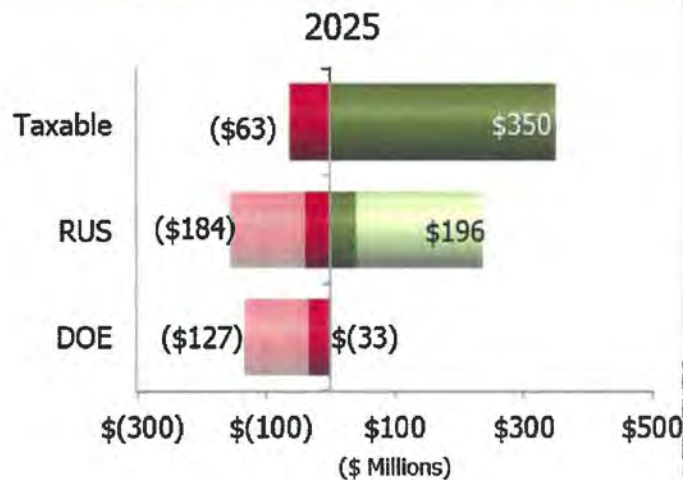
As of
May 23, 2025



- Represents 553 days of liquidity on hand.

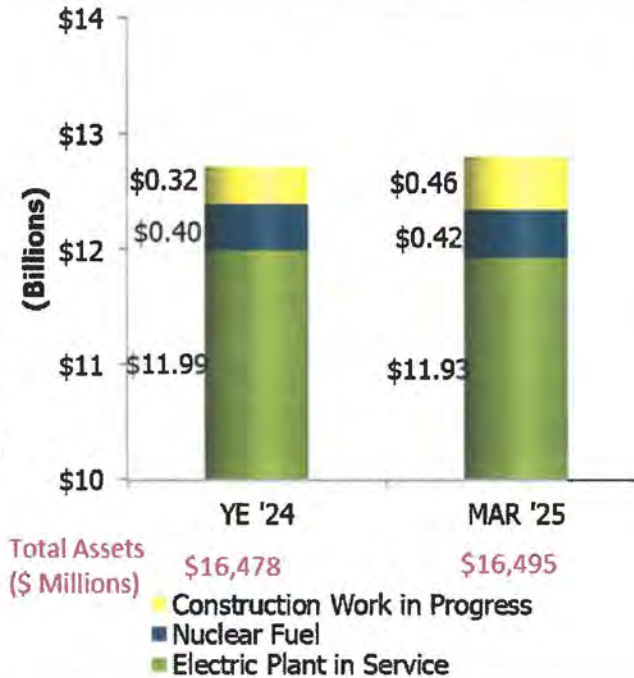
^(a) \$40.53 million of Oglethorpe's Tax-Exempt Bonds are in a weekly variable rate backed by Oglethorpe's own liquidity, which it is reserving to support these bonds.

Secured Long Term Debt

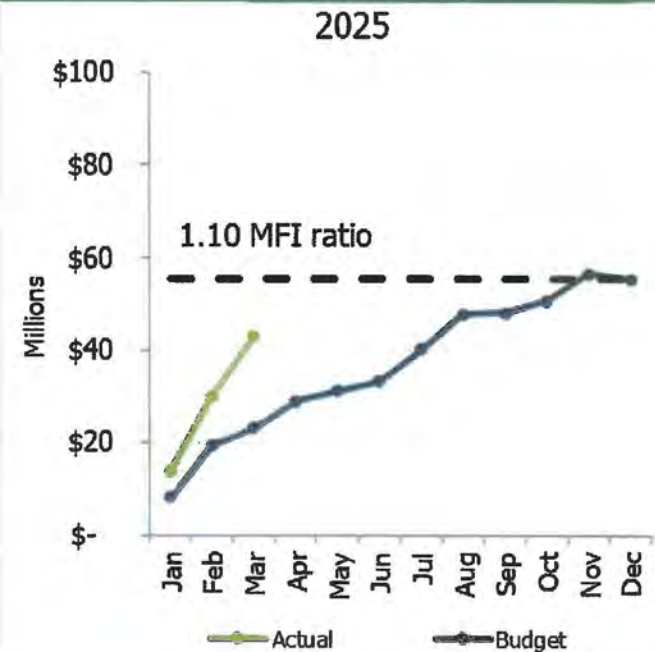


Secured LT Debt (4.30.25): \$12.7 billion
Weighted Average Cost: 4.04%

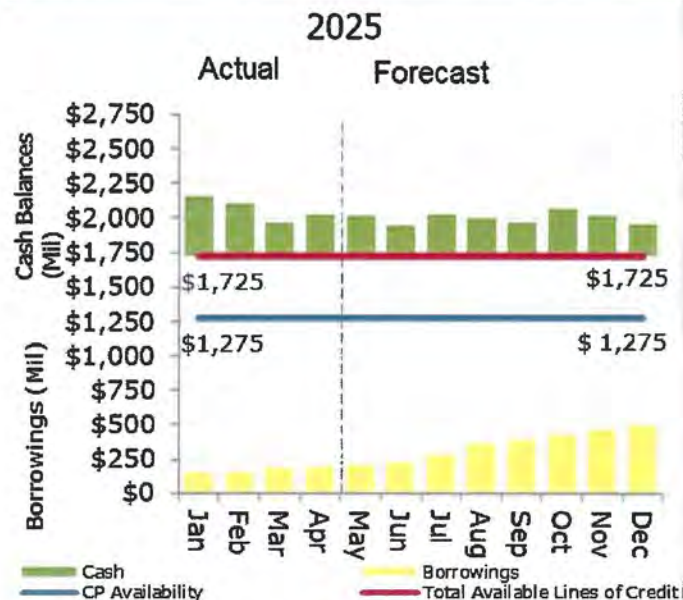
Balance Sheet Electric Plant



Net Margin

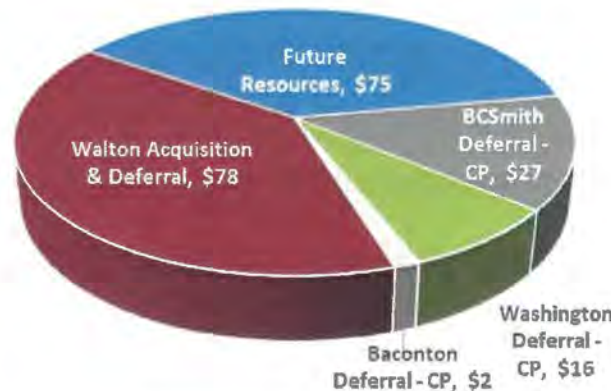


Liquidity



Interim CP Financing

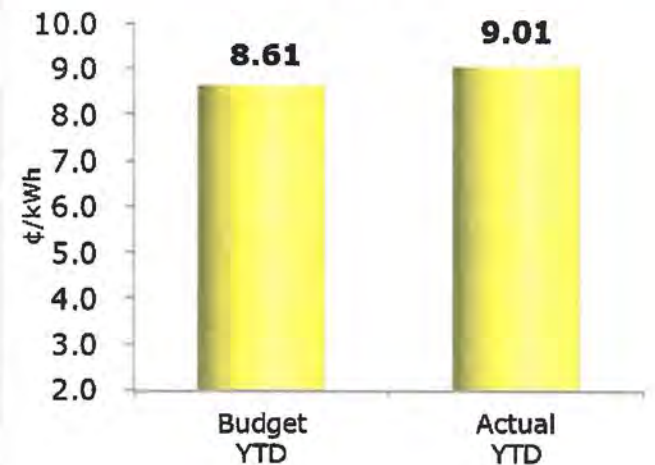
April 30, 2025



Average Cost of Funds: 4.73%
(dollars in millions)

Wholesale Power Cost

2025



**Designation Study Report
Yates 8-10 – Coweta County, GA
Designation (1326 MW)
March 12, 2024**

Notice to the Requesters of Transmission Planning Study Information

The following studies have been conducted starting with load flow base cases developed for use as one possible scenario of the future that could occur. These base cases incorporate the most recent information available concerning loads, transmission enhancements, committed generation, firm transactions, and other information pertinent to building load flow cases. For later years, they also incorporate assumptions on transmission and generation additions that may not be budgeted and for which commitments may not have been made by the entities represented in the models. Information from other transmission owners within the Southern Balancing Authority Area (SBAA) was obtained and incorporated in these models. The systems external to the SBAA were either obtained from the given Balancing Authority or from the most recent NERC MMWG cases. Southern Companies take no responsibility for the information provided by others in the performance of the studies. The cases represent the best effort of Southern Companies to develop load flow base cases for use as a starting point for budgeting and other types of studies at the point in time the analysis is performed. Modifications to the load flow cases may be required as part of any such studies. Southern Companies make no claim that the models represent a commitment to build any of the facilities in the models and maintain the right to change the models as additional information becomes available or additional possible scenarios are needed. The decision to use the studies or underlying assumptions for any purpose is the sole responsibility of the user. This document reports the results from the analysis of the requested service and does not represent an offer of transmission service.

Requested Designation & OASIS Reservation Detail

Customer	Facility Name	County, State	Designation Amount	Plant Type
SOCO	Yates 8-10	Coweta County, GA	1326 MW	Combustion Turbine (CT)

AREF	Source	Sink	MW	Dates	Designation Voltage
102024963	YATES.SOCO	SOCOLOAD.NTWK	1326	11/01/2026 – 08/01/2072	230 kV

Executive Summary

1. "Designation Request" shall hereafter refer to the designation of 1326 MW at Plant Yates Units 8-10.
2. Local area analysis identified constraints resulting from the Designation Request. See the "Local Area System Impacts" section of this report for additional information.
3. This designation cannot be fully accommodated until Summer 2028. Yates 9-10 are eligible for consideration as Designated Resources with Temporary Limitations (DRTL) until Summer 2028 when all required projects can be in-service. Generation redispatch will be utilized to maximize firm capability in the interim. See Tables 1 and 2.
4. Stability analysis did not identify constraints resulting from the Designation Request. See the "Stability Impacts" section of this report for additional information.
5. A review of Nuclear Plant Offsite Power requirements did not identify any constraints resulting from the Designation Request. See the "Nuclear Plant Offsite Power Impacts" section of this report for additional information.
6. An assessment of the impact to transfer capability indicates that the Designation Request does not limit the ability of Southern Companies to serve current firm obligations on Southern Balancing Authority Area interfaces during the timeframe requested. See the "Interface Transfer Capability Impacts" section of this report for additional information.
7. Based on the analysis included in this report, the designation can be provided pursuant to Table 1.

Generator Interconnection System Impact Study

April 12, 2024

IC-1217

470 MW

Jackson County, GA

ERIS & NRIS



Notice to The Requesters of Transmission Planning Study Information

The following studies have been conducted starting with power flow base cases developed for use as one possible scenario of the future that could occur. These base cases incorporate the most recent information available concerning loads, transmission enhancements, committed generation, firm transactions and other information pertinent to building power flow cases. For later years, they also incorporate assumptions on transmission and generation additions that may not be budgeted and for which commitments may not have been made by the entities represented in the models. Information from other transmission owners within the Southern Balancing Authority Area (SBAA) was obtained and incorporated in these models. The systems external to the SBAA were either obtained from the given control area or from the most recent MMWG cases. Southern Companies take no responsibility for the information provided by others in the performance of the studies. The cases represent Southern Companies' best effort in developing power flow base cases for use as a starting point for budget and other types of studies, at the point in time the analysis is done. Modifications may be required to the power flow cases as part of any such studies. Southern Companies do not represent the models as a commitment to build any of the facilities in the models and maintains the right to change the models as additional information becomes available or additional possible scenarios are needed. The decision to use the studies or underlying assumptions for any particular purpose is the sole responsibility of the user. This document reports the results from the analysis of the requested service and does not represent an offer of transmission service.

E. Cost and Timeline Estimates

[Return to Results Summary](#)

This portion of the interconnection study provides estimates for the cost and completion time of modifications and system improvements required for the Proposed Generating Facility.

All “Project Completion Times” in the tables below start after (i) a customer provided commitment to proceed and (ii) receiving survey coordinates of the corners of the interconnecting substation property. Estimated project completion times do not take into account delays due to potential issues with land acquisitions, delivery of long lead time items, and ability to schedule necessary line outages. In the event such issues occur, completion of interconnection facilities required for in-service could be delayed. If any land acquisition requires condemnation proceedings, additional time will be added to the schedule.

All cost estimates are defined in inflation adjusted dollars assuming the requested In-Service Date (**2029 dollars**) for the Proposed Generating Facility. These cost estimates represent the capital cost for the identified interconnection projects but do not include potential customer tax liabilities, operation and maintenance costs, Interconnection Agreement monthly administration charge (typically \$5,000/month), transmission service charges or costs for transmission system upgrades required for delivery of energy, or costs for customer owned interconnection facilities.

For the **System Impact Study**, the following estimates are non-binding and are provided to aid the customer in the determination of continuation for the proposed interconnection. The projects shown in this section do not take outage scheduling into consideration. This will be reviewed in the Interconnection **Facilities Study** stage to determine the impact on construction time and cost.

E.1. Summary of Estimates

The Transmission Owner, **Georgia Power Company (GPC)**, estimates the following for cost and completion time necessary from a customer provided commitment to proceed in order to complete the necessary interconnection upgrades for the Proposed Generating Facility. **The following estimates do not include the cost of any Affected System upgrades.**

E.1.1. Cost and Completion Time Estimates:

ERIS – Cost Estimate (Tables e.3.a and e.3.b)	\$10,100,000
ERIS – Completion Time (Section E.1.2)	30 - 36 months from Notice to Proceed.
ERIS Contingent Facilities – Cost Estimate (Table e.4.a)	None identified.
NRIS – Cost Estimate (Tables e.3.a, e.3.b, e.5.a)	\$12,700,000
NRIS – Completion Time (Section E.1.2)	30 - 36 months from Notice to Proceed.
NRIS Contingent Facilities – Cost Estimate (Tables e.4.a and e.6.a)	None identified.

E.3. Required Interconnection Transmission Upgrades

[Return to Results Summary](#)

The following projects and costs in **Section E.3** are required for the interconnection of the Proposed Generating Facility for either requested ERIS or NRIS product.

Table e.3.a. Southern Companies Interconnection Upgrades – From Change of Ownership to POI and Other Directly Assignable Costs

Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
IC-1217 Interconnecting Substation				
- Install Dual Line Current Differential protection panel for the IC-1217 230 kV line via fiber. Anti-Islanding dual channel transfer trip will be implemented via fiber optic cable using mirror bit communication. - Install three 230 kV CCVTs. Metering PTs could be used instead, if available. - Terminate the customer-installed fiber optic cable from the proposed Generating Facility for relaying, remote tripping, and data communications. - Install SCADA, CTs/PTs, and metering for two-way power flow. - At POI, install one advanced power quality meter, PQ sensors, and associated equipment to monitor harmonic currents and harmonic voltage distortion for all phases. - Install a disconnect switch for the generator line coming into the substation.	GPC	30 - 36 months	\$1,100,000	1-6
Athena – Center Primary 230 kV Line	GPC	30 - 36 months	\$300,000	4-5
Raise line. Generator tie-line to cross underneath.				
Athens – Center Primary (White) 115 kV Line	GPC	30 - 36 months	\$200,000	4-5
Raise line. Generator tie-line to cross underneath.				
Athens – Center Primary (Black) 115 kV Line	GPC	30 - 36 months	\$200,000	4-5
Raise line. Generator tie-line to cross underneath.				
North Commerce – Power Partners 46 kV Line	GPC	30 - 36 months	\$200,000	4-5
Modify line to accommodate Generator tie-line crossing				
Transmission Outages			TBD in Facilities Study	
Estimated costs of expenses associated with transmission outages necessary for the interconnection of the Proposed Generating Facility.				
Total Cost of Table e.3.a:			\$2,000,000	

[Return to Results Summary](#)

Table e.3.c. Affected Systems Interconnection Upgrades

Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
Center Primary Substation (GTC) - Replace overstressed breaker C1. - Potential grounding modifications to be determined by GTC. - IC-1217 POI 230 kV line: Use existing DCUB line protection panel. Update relay settings. - Breaker Failure Transfer Trip - Install a dual-channel transfer trip receiver panel on IC-1217 230 kV line. - Anti-Islanding Protection - Install a single channel transfer trip transmitter panel on the IC-1217 230 kV line.	Georgia Transmission Corporation (GTC)	TBD By GTC	TBD By GTC	7
Commerce #4 (MEAG) 115 kV Substation Potential Upgrades to be determined by MEAG.	The Municipal Electric Authority of Georgia (MEAG)	TBD by MEAG	TBD by MEAG	7

E.4. Contingent Facilities

Contingent Facilities shall mean those unbuilt interconnection facilities and network upgrades upon which the interconnection request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the interconnection request or a reassessment of the interconnection facilities and/or network upgrades and/or costs and timing.

Table e.4.a. Southern Companies *PRIOR-QUEUED* Interconnection Upgrades

Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
None identified				

E.5. Additional Transmission Upgrades Required for NRIS

[Return to Results Summary](#)

The following projects and costs are required only for the requested NRIS product and assume that all required interconnection transmission facilities in **Section E.3** are installed.

Table e.5.a. Southern Companies NRIS Transmission System Upgrades

ID	Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
P1	Center Primary – IC-1217 Interconnecting Substation 230 kV Line	GPC	24 - 30 months	\$2,600,000	
	Rebuild approximately one (1) mile of 230 kV transmission line from Center Primary to the new IC-1217 Interconnecting Substation.				
Total Cost of Table e.5.a:				\$2,600,000	

Table e.5.b. Affected Systems NRIS Transmission System Upgrades

ID	Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
AFS1	Center Primary – Clarksboro 230 kV Line	Georgia Transmission Corporation (GTC)	TBD by GTC	TBD by GTC	
	Rebuild approximately eight (8) miles of 230 kV transmission line from Center Primary (GTC) to Clarksboro (GTC).				

E.6. Contingent Facilities Transmission Upgrades Required for NRIS

Contingent Facilities shall mean those unbuilt interconnection facilities and network upgrades upon which the interconnection request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the interconnection request or a reassessment of the interconnection facilities and/or network upgrades and/or costs and timing.

Table e.6.a. Southern Companies PRIOR-QUEUED NRIS Transmission System Upgrades

ID	Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
None identified					

Generator Interconnection System Impact Study

April 12, 2024

IC-1218

640 MW

Lee County, AL

ERIS & NRIS



Notice to The Requesters of Transmission Planning Study Information

The following studies have been conducted starting with power flow base cases developed for use as one possible scenario of the future that could occur. These base cases incorporate the most recent information available concerning loads, transmission enhancements, committed generation, firm transactions and other information pertinent to building power flow cases. For later years, they also incorporate assumptions on transmission and generation additions that may not be budgeted and for which commitments may not have been made by the entities represented in the models. Information from other transmission owners within the Southern Balancing Authority Area (SBAA) was obtained and incorporated in these models. The systems external to the SBAA were either obtained from the given control area or from the most recent MMWG cases. Southern Companies take no responsibility for the information provided by others in the performance of the studies. The cases represent Southern Companies' best effort in developing power flow base cases for use as a starting point for budget and other types of studies, at the point in time the analysis is done. Modifications may be required to the power flow cases as part of any such studies. Southern Companies do not represent the models as a commitment to build any of the facilities in the models and maintains the right to change the models as additional information becomes available or additional possible scenarios are needed. The decision to use the studies or underlying assumptions for any particular purpose is the sole responsibility of the user. This document reports the results from the analysis of the requested service and does not represent an offer of transmission service.

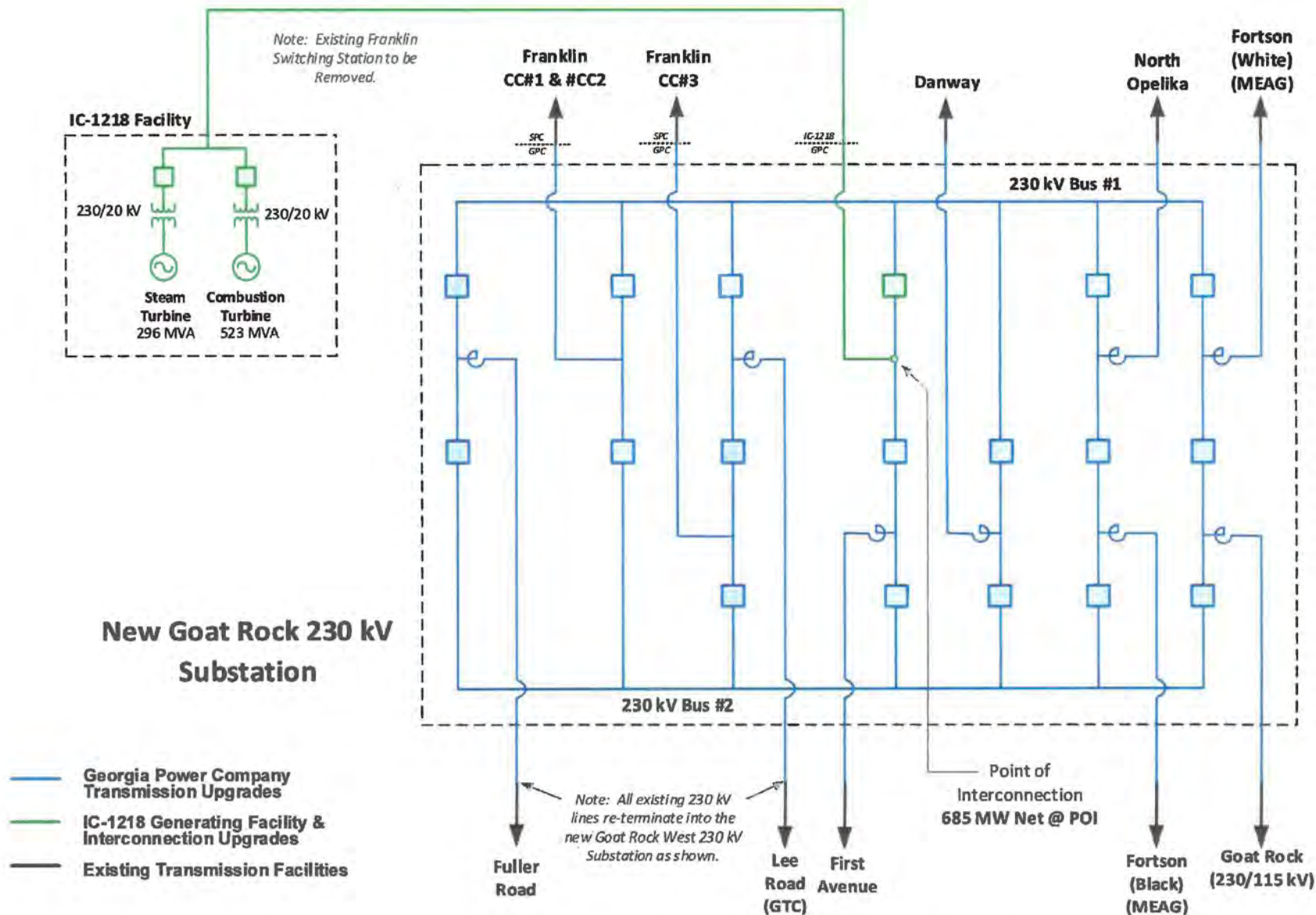


Diagram a.6.a. Proposed Interconnection Configuration for the Proposed Generating Facility

C. Interconnection Evaluation

[Return to Results Summary](#)

This portion of the interconnection study determines the requirements for the proposed interconnection configuration and identifies any necessary modifications and system improvements. This evaluation includes any relevant active prior-queued Interconnection Requests (shown in **Appendix A**) and the interconnection upgrades associated with those requests. The interconnection evaluation results identified in this section are the same for either requested ERI or NRIS product.

C.1. Interconnection Evaluation – Reactive Power and Voltage Schedule

C.1.1. Reactive Power

The Reactive Power Requirement for a generator interconnected to a system with a voltage of **40 kV** and higher specifies that it must have the capability to produce and absorb at least 0.33 MVARs (dynamic reactive power) at the Point of Interconnection (POI) for each MW supplied at the POI. The total dynamic range requirement is 0.66 MVAR/MW. Based on the modeled system configuration and the generating facility capabilities shown in **Table c.1.1a**:

- The Proposed Generating Facility **meets the minimum** reactive power production.
- The Proposed Generating Facility **meets the minimum** reactive power absorption.
- The Proposed Generating Facility **meets the minimum** total dynamic range.

Table c.1.1.a. Reactive Power

Unit	Test Voltage	High Limit	Actual	Low-Side Gross			Station Service		Net Production at POI			Dynamic Range
	High Side	Low Side	Low Side Voltage	MW	MVAR	MVAR/MW	MW	MVAR	MW	MVAR	MVAR/MW	MVAR/MW
CT	1.01	1.05	1.0496	405	275	0.6790	6.500	4.000				
ST	1.01	1.05	1.0473	235	140	0.5957	6.500	4.000				
CC Total				640			13.00	8.00	624.87	320.49	0.513	
Unit	Test Voltage	Low Limit	Actual	Low-Side Gross			Station Service		Net Absorption at POI			1.023
	High Side	Low Side	Low Side Voltage	MW	MVAR	MVAR/MW	MW	MVAR	MW	MVAR	MVAR/MW	
CT	1.04	0.95	0.9743	405	-136	-0.3358	6.500	4.000				
ST	1.04	0.95	0.9602	235	-93	-0.3957	6.500	4.000				
CC Total				640			13.00	8.00	624.99	-318.78	-0.510	

This evaluation was performed assuming the **235.75 kV tap** setting position for the main step-up transformers as the most favorable tap setting. If there is any technical reason that other tap positions are used, additional evaluation may be needed at that time.

C.3. Interconnection Evaluation – Stability

[Return to Results Summary](#)

Stability analysis **identified the following requirements** due to the Proposed Generating Facility:

- Pilot relaying scheme on the IC-1218 – North Opelika 230 kV line.
- Pilot relaying scheme on the Goat Rock – Bartletts Ferry 115 kV line (Black).
- Pilot relaying scheme on the Goat Rock – Bartletts Ferry 115 kV line (White).
- Total breaker failure clearing time at the new **Goat Rock 230 kV Substation** bus of 8 cycles or less.
- Total breaker failure clearing time at existing Goat Rock TS 115 kV bus of 8 cycles or less.

Stability analysis **did not identify any deficiencies** with the customer provided dynamic modeling data.

C.4. Interconnection Evaluation – Protection

Protection analysis **identified the following modifications** are required due to the interconnection of the Proposed Generating Facility.

C.4.1. Protection Requirements – Southern Companies

- **New Goat Rock 230 kV Substation**
 - Install one new 230 kV, 80kA, 2-cycle breaker at the new Goat Rock 230 kV breaker-and-a-half substation with fiber optic cable to the Proposed Generating Facility.
 - Install Dual Line Current Differential protection panel for the **IC-1218** 230 kV line via fiber. Anti-Islanding dual channel transfer trip will be implemented via fiber optic cable using mirror bit communication.
 - 230 kV Lines at the new Goat Rock 230 kV Substation: Use existing line protection panels. Update relay settings.
 - 230 kV Bus #1 and Bus #2: Use existing bus differential protection panels. Update relay settings.
 - 230/115kV Bank A Lines: Use existing transformer differential protection panels. Update relay settings.
- **Danway 230 kV Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.
- **North Opelika 230 kV Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.
- **First Avenue 230 kV Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.
- **Fuller Road 230 kV Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.
- **Franklin CC#1 and CC#2 (SPC) 230 kV Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.
- **Franklin CC#3 230 kV (SPC) Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.
- **IC-1218 Generating Facility**
 - Goat Rock 230 kV Line: The customer should include two (2) line current differential devices capable of receiving transfer trip using mirror bit communication via fiber optic.

C.4.2. Protection Requirements – Affected Systems

- **Fortson (MEAG) 230 kV Substation**
 - Goat Rock (White) 230 kV line: Use existing line protection panels. Update relay settings.
 - Goat Rock (Black) 230 kV line: Use existing line protection panels. Update relay settings.
- **Lee Road (GTC) 230 kV Substation**
 - Goat Rock 230 kV line: Use existing line protection panels. Update relay settings.

[Return to Results Summary](#)

D. Delivery Screen

This study is not intended as an offer of delivery service and may not be representative of the availability of transmission service at any particular date.

This portion of the interconnection study evaluates the potential capability of the transmission system to receive the requested output (net capacity listed in **Section A.2**) of the Proposed Generating Facility at the POI. For study purposes, the output of the Proposed Generating Facility is studied as being delivered to Southern Companies' aggregate load. Analysis is based upon the forecasted system configurations and commitments as known at the time of this study. The transmission system capability delivery screens consider the year in which the generator is requesting commercial operation and the remainder of the planning horizon (**2030 through 2033**) to provide an account of the expected system configuration in the years following interconnection.

D.1. ERIIS Delivery Screen

The ERIIS product does not convey any right to deliver electricity and the following screening results are provided for informational purposes only.

For ERIIS, this section of the report identifies the maximum output of the Proposed Generating Facility without any additional network upgrades (additional to those required for interconnection identified in **Table e.3.a**) and provides a summary of possible transmission facility impacts. The ERIIS delivery screen does not include the impact to delivery of prior-queued Interconnection Requests that do not have confirmed transmission service or designation.

[Return to Results Summary](#)

D.1.2. ERIS Delivery Screen – System Strength

This section is not applicable to IC-1218.

D.1.3. ERIS Delivery Screen – Bus Ampacity

The bus ampacity delivery screen **did not identify** thermal constraints within neighboring substations due to the delivery of the requested full output of the Proposed Generating Facility.

D.1.4. ERIS Delivery Screen – Stability

The stability delivery screen **did not identify** constraints to deliver the full output of the Proposed Generating Facility.

D.1.5. ERIS Delivery Screen – Interface Transfer Capability

The transfer capability screen evaluates import and export capability to ensure firm obligations across the interfaces are not negatively impacted. The transfer capability screen **did not identify** constraints due to the delivery of the requested full output of the Proposed Generating Facility, as shown in **Table d.1.5.a.**

Table d.1.5.a. Impacts to Interface Capability

Year	Interface	Limiting Facility	Thermal Loading (%)		Contingency	Scenario	MW Limit
			PRE-Request	POST-Request			
-	-	None Identified	-	-	-	-	-

Scenarios:

None

D.1.6. ERIS Delivery Screen – Nuclear Plant Offsite Power

The impact on voltage at existing nuclear facilities resulting from the addition of the Proposed Generating Facility has been evaluated, and the addition of the Proposed Generating Facility **does not negatively impact** the ability to meet the Southern Nuclear Plant Interface Requirement (NPIR) for the bus voltage range, as required per NERC Standard NUC-001-3.

D.2.5. NRIS Delivery Screen – Interface Transfer Capability

[Return to Results Summary](#)

The transfer capability screen evaluates import and export capability to ensure firm obligations across the interfaces are not negatively impacted. The transfer capability screen **did not identify** constraints due to the delivery of the requested full output of the Proposed Generating Facility, as shown in **Table d.2.5.a.**

Table d.2.5.a. Impacts to Interface Capability

Year	Interface	Limiting Facility	Thermal Loading %		Contingency	Scenario	Project
			PRE-Request	POST-Request			
		None Identified					

Scenarios:

None

D.2.6. NRIS Delivery Screen – Nuclear Plant Offsite Power

The impact on voltage at existing nuclear facilities resulting from the addition of the Proposed Generating Facility has been evaluated, and the addition of the Proposed Generating Facility **does not negatively impact** the ability to meet the Southern Nuclear Plant Interface Requirement (NPIR) for the bus voltage range, as required per NERC Standard NUC-001-3.

E.1.2. Milestone Dates:

[Return to Results Summary](#)

Based on the customer requested milestone dates and/or the completion time estimates, the following schedule deficiencies were identified:

- 54 - 60 months are needed from the customer provided Notice to Proceed under a Generator Interconnection Agreement or Engineering & Procurement Agreement in order to reach the In-Service Date.
- Requested In-Service Date is not attainable.
- Requested In-Service Date falls within summer season. APC/GPC cannot guarantee the availability of transmission outage windows during that period of time.
- NRIS: The requested COD is not attainable. 78 - 84 months are needed from the customer provided Notice to Proceed under a Generator Interconnection Agreement or Engineering & Procurement Agreement in order to reach the COD.
- The transmission outage window and construction related dates supplied in this Interconnection Study are not reserved for Customer. These dates and related outages are based upon, among other things, expected events and factors (e.g., outage scheduling, resource commitments) and the assumption that Customer will provide the Notice to Proceed, will not suspend work on the Project, and will move forward with the development of the Project in accordance with the milestone dates. If any of these expected events, factors and assumptions prove to be incorrect, or unexpected events cause a material impact, such outage(s) and dates may be unavailable. If the outages and/or dates are materially impacted and the Customer moves forward with the Project, Southern Companies will endeavor to find (e.g., through construction sequencing) new transmission outage window(s) and construction related dates (e.g., in-service).

Note: Further information can be found in the Generator Interconnection Agreement Implementation Process document located on Southern Companies' OASIS website².

E.2. Special Timeline Notes

E.2.1. Affected Systems:

The customer should contact the potential Affected System Operator(s) identified below to initiate an affected system review for this interconnection. Southern Companies recommend contacting the potential Affected System Operator(s) prior to the start of the Facilities Study so that any Affected System review can be performed in parallel with the Facilities Study. Affected System Operator(s) may invoke their right to study any or all of their facilities that are suspected to be impacted by this interconnection request, which could result in additional transmission system improvements to those initially identified. Prior to approving Initial Synchronization, Southern Companies' will require: (1) written confirmation from all Affected System Operators that any impacts to an Affected System have been mitigated, or (2) written confirmation that the potential Affected System Operator did not identify any impacts to their facilities.

- **The Municipal Electric Authority of Georgia (MEAG)**
 - Shen Ting: 1-770-661-2766, sting@meagpower.org
- **Georgia Transmission Corporation (GTC)**
 - Contact information available at <https://www.oasis.oati.com/gtc/index.html>

² www.oasis.oati.com/SOCO

Table e.3.b. Southern Companies Interconnection Upgrades – Beyond the POI

Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
New Goat Rock 230 kV Substation - Install one new 230 kV, 80 kA, 2-cycle breaker at the to-be-built IC-1218 230 kV Interconnecting breaker-and-a-half substation with fiber optic cable to the Proposed Generating Facility. Install (2) breaker control panels in the control house. Install a high-speed breaker-failure relay for the new breaker. 230 kV Lines at new Goat Rock 230 kV Substation: Use existing line protection panels. Update relay settings. 230 kV Bus #1 and Bus #2: Use existing bus differential protection panels. Update relay settings. 230/115 kV Bank A Lines: Use existing transformer differential protection panels. Update relay settings.	GPC	54 - 60 months	\$2,500,000	1-4
First Avenue 230 kV Substation Goat Rock 230 kV Line: Use existing line protection panels. Update relay settings	GPC	54 - 60 months	\$15,000	
Existing Goat Rock 115 kV Substation - Total breaker failure clearing time at existing Goat Rock TS 115kV to be 8 cycles or less to meet stability requirements. - Replace existing six (6) 115kV PCBs at existing Goat Rock TS with 115kV, 40kA, 2-cycle breakers. - Replace existing six (6) 115kV breaker control relays with high-speed breaker-failure relays.	GPC	54 - 60 months	\$384,000	
Relay and Protection Settings Changes (APC) - Danway 230 kV Substation: Goat Rock 230 kV line: Use existing line protection panels. Update relay settings. - North Opelika 230 kV Substation: Goat Rock 230 kV line: Use existing line protection panels. Update relay settings. - Fuller Road 230 kV Substation: Goat Rock 230 kV line: Use existing line protection panels. Update relay settings	APC	54 - 60 months	\$35,000	
Total Cost of Table e.3.b:			\$2,934,000	

[Return to Results Summary](#)

E.5. Additional Transmission Upgrades Required for NRIS

The following projects and costs are required only for the requested NRIS product and assume that all required interconnection transmission facilities in **Section E.3** are installed.

Table e.5.a. Southern Companies NRIS Transmission System Upgrades

ID	Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
P1	Fortson – Goat Rock (White) 230 kV Line Reconductor approximately ten (10) miles of 230 kV transmission line from Fortson (GTC) to Goat Rock.	GPC	78 - 84 months*	\$26,000,000	
P2	Fortson – Goat Rock (Black) 230 kV Line Reconductor approximately ten (10) miles of 230 kV transmission line from Fortson (GTC) to Goat Rock.	GPC	78 - 84 months*	\$26,000,000	
P3	Danway – Goat Rock 230 kV Line Reconductor approximately twenty-four (24) miles of 230 kV transmission line from Danway SS to Goat Rock.	APC	78 - 84 months*	\$62,000,000	
P4	North Opelika – Goat Rock 230 kV Line Reconductor approximately eighteen (18) miles of 230 kV transmission line from North Opelika to Goat Rock.	APC	78 - 84 months*	\$47,000,000	
Total Cost of Table e.5.a:				\$161,000,000	

* Projects P1, P2, P3, and P4 must be completed sequentially for a total project completion time of 78 – 84 months.

E.6. Contingent Facilities Transmission Upgrades Required for NRIS

Contingent Facilities shall mean those unbuilt interconnection facilities and network upgrades upon which the interconnection request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the interconnection request or a reassessment of the interconnection facilities and/or network upgrades and/or costs and timing.

Table e.6.a. Southern Companies PRIOR-QUEUED NRIS Transmission System Upgrades

ID	Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
-	None identified			-	

Table APA.2. Prior-Queued Confirmed Transmission Service Considered in the Interconnection Evaluation

Ref ID	POR	Source	MW	POD	Begin	End
100652168	SOCO	THEOCOGEN.SOCO	5	SOCO	12/1/2024	1/1/2041
101156475	SOCO	SOCOGEN.SOCO	11	EVERGREEN.NTWK	1/1/2024	1/1/2029
100920423	SOCO	FABLESOL.SOCO	78	SOCO	3/1/2026	2/1/2050
99222883	SOCO	SANDERSVI.SOCO	292	SC	1/1/2029	1/1/2034
99468803	GTC	WALTONCO (WALTON CTY NLR)	576	OPCLOAD	6/1/2024	6/1/2054
N/A	SOCO	NITS AMEA Alex-Dadeville Load	10	SOCO	4/1/2025	1/1/2046
100324190	SOCO	SATURSOL1.SOCO	80	SOCO	12/1/2026	1/1/2042
100324205	SOCO	SATURSOL2.SOCO	80	SOCO	12/1/2026	1/1/2042
101184975	SOCO	MILLER.SOCO	1000	TVA.TVA	6/1/2024	6/1/2029
100579607	GTC	HATCH	527	OPCLOAD	9/1/2023	12/30/2049
100579659	GTC	SCHERER	1030	OPCLOAD	9/1/2023	12/30/2049
100579701	GTC	ROCKY MOUNTAIN	817	OPCLOAD	9/1/2023	12/30/2049
100579746	GTC	HARTWELL	354	OPCLOAD	9/1/2023	12/30/2049
100579773	GTC	SEWELL CREEK	518	OPCLOAD	9/1/2023	12/30/2049
100579783	GTC	TALBOT	726	OPCLOAD	9/1/2023	12/30/2049
100579831	GTC	TA SMITH 500	686	OPCLOAD	9/1/2023	12/30/2049
100579842	GTC	TA SMITH 230	686	OPCLOAD	9/1/2023	12/30/2049
100599595	SOCO	DOURUNSOL.SOCO	-220	SOCO	12/1/2023	1/1/3000
100866410	GTC	GTC	300	MEAG	1/1/2024	1/1/2025
100866412	SOCO	SOCO	300	MEAG	1/1/2024	1/1/2025
100866416	MEAG	MEAG SCHERER	300	GTC	1/1/2024	1/1/2025
100866420	MEAG	MEAG SCHERER	300	SOCO	1/1/2024	1/1/2025
100977597	SOCO	GASTON.SOCO	73 - Summer, 24 - Winter	SOCO	9/1/2026	3/1/2040
101035201	SOCO	SRMETTER.GTC	80	SOCO	1/1/2046	9/1/2055
101033797	GTC	SR ROBINS	250	GTC	6/1/2029	12/31/2040
101213384	GTC	OPC SYSTEM	25	FPL.FPL	12/31/2024	12/31/2029
101501181	SOCO	GREENVILL.SOCO	-80	SOCOLOAD	12/4/2023	1/1/3000
101527376	SOCO	WANSLEY.SOCO	25	AMEALOAD.NTWK	12/1/2024	1/1/2026
101583627	GTC	FRANKLIN.SOCO	70	DALTLOAD.DALT	1/1/2024	1/1/2029
101615818	GTC	HILLABEE	50	OPCLOAD.GTC	12/31/2023	12/30/2028

For a complete list of active Interconnection Requests please refer to the Southern Companies' OASIS at <http://www.oasis.oati.com/SOCO/SOCODocs/Active-Gen-IC-Requests.pdf>.

For a complete list of transmission service requests please refer to the Southern Companies' OASIS at <http://www.oasis.oati.com/SOCO>.

For a complete list of current designations please refer to the Southern Companies' OASIS at https://oasis.oati.com/woa/docs/SOCO/SOCODocs/DNR_Comparison_and_Update_Tool_-_2023_-_Updated_8_2_2023.pdf

Generator Interconnection System Impact Study

April 12, 2024

IC-1219

640 MW

Hart County, GA

ERIS & NRIS



Notice to The Requesters of Transmission Planning Study Information

The following studies have been conducted starting with power flow base cases developed for use as one possible scenario of the future that could occur. These base cases incorporate the most recent information available concerning loads, transmission enhancements, committed generation, firm transactions and other information pertinent to building power flow cases. For later years, they also incorporate assumptions on transmission and generation additions that may not be budgeted and for which commitments may not have been made by the entities represented in the models. Information from other transmission owners within the Southern Balancing Authority Area (SBAA) was obtained and incorporated in these models. The systems external to the SBAA were either obtained from the given control area or from the most recent MMWG cases. Southern Companies take no responsibility for the information provided by others in the performance of the studies. The cases represent Southern Companies' best effort in developing power flow base cases for use as a starting point for budget and other types of studies, at the point in time the analysis is done. Modifications may be required to the power flow cases as part of any such studies. Southern Companies do not represent the models as a commitment to build any of the facilities in the models and maintains the right to change the models as additional information becomes available or additional possible scenarios are needed. The decision to use the studies or underlying assumptions for any particular purpose is the sole responsibility of the user. This document reports the results from the analysis of the requested service and does not represent an offer of transmission service.

E.1.2. Milestone Dates:[Return to Results Summary](#)

Based on the customer requested milestone dates and/or the completion time estimates, the following schedule deficiencies were identified:

- **30 - 36 months are needed from the customer provided Notice to Proceed under a Generator Interconnection Agreement or Engineering & Procurement Agreement in order to reach the In-Service Date.**
- **Requested In-Service Date falls within summer season. GPC cannot guarantee the availability of transmission outage windows during that period of time.**

Note: Further information can be found in the Generator Interconnection Agreement Implementation Process document located on Southern Companies' OASIS website³.

E.2. Special Timeline Notes**E.2.1. Affected Systems:**

The customer should contact the potential Affected System Operator(s) identified below to initiate an affected system review for this interconnection. Southern Companies recommend contacting the potential Affected System Operator(s) prior to the start of the Facilities Study so that any Affected System review can be performed in parallel with the Facilities Study. Affected System Operator(s) may invoke their right to study any or all of their facilities that are suspected to be impacted by this interconnection request, which could result in additional transmission system improvements to those initially identified. Prior to approving Initial Synchronization, Southern Companies' will require: (1) written confirmation from all Affected System Operators that any impacts to an Affected System have been mitigated, or (2) written confirmation that the potential Affected System Operator did not identify any impacts to their facilities.

- **Georgia Transmission Corporation (GTC)**
 - Contact information available at <https://www.oasis.oati.com/gtc/index.html>

³www.oasis.oati.com/SOCO

Table e.3.b. Southern Companies Interconnection Upgrades – Beyond the POI

Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
Bio TS 230 kV Substation				
- Install two (2) new 230 kV, 40 kA, 2-cycle breakers at the to-be-built IC-1219 230 kV Interconnecting breaker-and-a-half substation with fiber optic cable to the Proposed Generating Facility. Install (2) breaker control panels in the control house. - GPCQF-1034 230 kV line: Use existing DCUB line protection panel. Update relay settings. - Hartwell Energy (GTC) 230 kV line: Use existing DCUB line protection panel. Update relay settings. - IC-1194 230 kV line: Use existing step distance line protection panel. Update relay settings. 230/115 kV Bank A: Use existing transformer differential protection panel. Update relay settings. 230/115 kV Bank C: Use existing transformer differential protection panel. Update relay settings. 230 kV Bus #1: Use existing bus differential protection panel. Update relay settings and make necessary wiring modifications to include new IC-1219 230 kV line and associated breakers. 230 kV Bus #2: Use existing bus differential protection panel. Update relay settings and make necessary wiring modifications to include new IC-1219 230 kV line and associated breakers.	GPC	30 - 36 months	\$2,500,000	1-4
GPCQF-1034 Substation				
Bio 230 kV line: Use existing DCUB line protection panel. Update relay settings	GPC	30 - 36 months	\$15,000	
Total Cost of Table e.3.b:			\$2,515,000	

E.4. Contingent Facilities

[Return to Results Summary](#)

Contingent Facilities shall mean those unbuilt interconnection facilities and network upgrades upon which the interconnection request’s costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the interconnection request or a reassessment of the interconnection facilities and/or network upgrades and/or costs and timing.

Table e.4.a. Southern Companies *PRIOR-QUEUED* Interconnection Upgrades

Description of Project	Facility Owner	Project Completion Time	Cost Estimate	Notes
None identified			–	

Notes:

1. The Transmission Owner will own, operate, and maintain the Interconnection Facilities in the **Bio TS 230 kV Substation**. Interconnection Customer to provide a substation site (including ingress/egress) acceptable to the Transmission Owner for the new interconnecting substation with substation site and access provided in accordance with the Transmission Owner’s guidelines. The generator owner may be required to purchase additional substation property for the interconnecting substation and transfer ownership or deed the property over to the Transmission Owner.
2. Interconnection Customer is responsible for the cost and installation of the communication circuit between the Proposed Generating Facility and the **Bio TS 230 kV Substation** and for coordinating with the Transmission Owner on the terminations.
3. The breakers and potential/current transformers are potentially long lead time items that can require 2 years or more for delivery.
4. Additional reconfiguration of existing lines outside the interconnecting substation could potentially be required based on site visit, survey, or final design and may not be included in this estimate.
5. Generator is responsible for obtaining necessary easements from ROW owner in order to cross the existing transmission ROW.
6. The customer should include two devices capable of receiving transfer trip using mirror bit communication via fiber optic.
7. Affected System Upgrades to be facilitated under a separate contract between Affected System and Interconnection Customer.

ENVIRONMENTAL ASSESSMENT
for construction of the proposed
LaGrange Primary-Oseligee Creek 230kV Transmission Line
and Oseligee Creek 230/25kV Substation

Troup County, Georgia

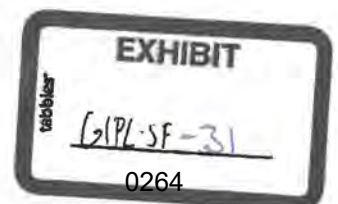


Rural Development | Rural Utilities Service
Environmental and Historic Preservation Division

prepared by:

Georgia Transmission Corporation
1979 Lakeside Parkway
Tucker, GA 30084

June 2025



4. PROJECT ALTERNATIVES

4.1 Electrical Alternatives

Several electrical alternatives were considered to respond to the system reliability issues identified in Section 3.0. Six electrical alternatives, including a “no action” alternative, are outlined below.

4.1.1 No Action Alternative

With this alternative, there are no environmental consequences as the Georgia ITS would not address the electrical reliability issues identified in Section 3. In addition, as generation at Franklin is dispatched at full output based on expected transmission service requests (TSRs), more thermal constraints will appear in the area. Per TPL-001-4, these thermal constraints must have a corrective action plan.

4.1.2 Preferred Corrective Action Plan / Proposed Action:

New LaGrange Primary – North Opelika 230kV Line (\$64 M)

- GTC – Construct approximately 15-mile 230 kV (100° 1351 ACSR conductor) from LaGrange Primary to the GA/AL state line. Utilize existing 115 kV corridors as needed. (\$30M)
- ITS – Construct a new metering station at the GA/AL line and terminate GTC and APC circuits. (\$2M)
- GPC – Modify Lagrange Primary Substation to terminate new 230 kV circuit to North Opelika. (\$2M)
- APC to construct an additional 15 miles within Alabama to the N. Opelika substation. (~ \$30M)

4.1.3 Brute Force (\$105 M)

- Dyer Road – East Roanoke (APC) 115 kV
 - 2029 Op Guide: Open Breakers 416880 and 416990 at Dyer Road
- Fortson – Lagrange Primary 230 kV
 - 2024 Rebuild 37.5 miles with 125° C 1351 ACSR
- Kia Motors - Lagrange 11 115 kV
 - 2028 Rebuild 10.6 miles with 100° C 1033 ACSR
- Kia Motors - Pittman Road 115 kV
 - 2026 Rebuild 4.6 miles with 100° C 1033 ACSR
- Pittman Road - West Point Dam (USA) 115 kV
 - 2027 Rebuild 3.2 miles with 100° C 795 ACSR

4.1.4 Butler – Thomaston 230kV (\$80 M)

- Convert Butler-Thomaston 115kV to 230kV using 100°C 1351 ACSR.
- Convert Butler 115KV bus, Wesley 115KV bus to 230KV bus
- Replace Butler 115/46 kV transformer with 230/46 kV transformer

Appendix B – Project Release

- Project Release: East Walton Project – 230 kV Portion: Georgia Transmission Corporation. (GTC), Tucker, GA, February 6, 2023.
- Project Release: East Walton Project – 500 kV Portion: Georgia Transmission Corporation. (GTC), Tucker, GA, April 5, 2018.

Environmental Assessment

East Central Georgia Reliability Project

APPENDICES

February 2025



Planning Grade Estimate

2/1/2023

Project Name: Bethabara - East Walton 230 kV Line
Project Number: P79467
Scope: Construct new 10 miles of 230 kV line from East Walton to Bethabara substation with (1) 1351 ACSS conductor for 170 degree C operation. (See Project # P79050 for the ALP.)

Project Cut-In Date 6/1/2027

Direct Charges

EC 50 - Construction Contract Labor	\$12,239,966.22
EC 64 - Owner Furnished Material	\$8,457,795.42
Land	\$0.00
Labor (40 & 54)	\$1,823,592.07
EC 56 - Professional Services	\$2,348,887.58
Legal	\$212,145.26
Other	\$117,613.45
Project Contingency & Escalation	\$2,799,999.72
Total Direct Cost	\$28,000,000

Indirect (overheads) **\$7,000,000**

Total Project Cost **\$35,000,000**

Retired Asset Value	\$0
ITS Investment	\$35,000,000
DSF Investment	\$0
TSF Investment	\$0

Net Change to Facility Investment **\$35,000,000**

Assumptions:

1. Estimate based on an estimate of \$3.5M per mile provided by Transmission Projects
2. Contingency costs set at 10% of direct costs. Cost is intended to cover high level nature of planning grade estimates.
3. Indirect cost assumptions include 25% of direct costs.

Planning Grade Estimate

2/1/2023

Project Name: East Walton - Jacks Creek 230 kV Line
Project Number: P79469
Scope: Construct approximately 9 miles of 230 kV line from East Walton to a new MEAG 230 kV S/S (Jack's Creek) in the Monroe area with 1351 ACSS conductor for 170 degree C operation. (See Project # P79060 for the ALP.)

Project Cut-In Date 6/1/2027

Direct Charges

EC 50 - Construction Contract Labor	\$11,015,969.60
EC 64 - Owner Furnished Material	\$7,612,015.88
Land	\$0.00
Labor (40 & 54)	\$1,641,232.87
EC 56 - Professional Services	\$2,113,998.82
Legal	\$190,930.73
Other	\$105,852.10
Project Contingency & Escalation	\$2,519,999.75
Total Direct Cost	\$25,200,000

Indirect (overheads) **\$6,300,000**

Total Project Cost **\$31,500,000**

Retired Asset Value	\$0
ITS Investment	\$31,500,000
DSF Investment	\$0
TSF Investment	\$0
Net Change to Facility Investment	\$31,500,000

Assumptions:

1. Estimate based on an estimate of \$3.5M per mile provided by Transmission Projects
2. Contingency costs set at 10% of direct costs. Cost is intended to cover high level nature of planning grade estimates.
3. Indirect cost assumptions include 25% of direct costs.

Planning Grade Estimate

2/1/2023

Project Name: Bostwick 230 kV Switching Station
Project Number: P79466
Scope: Construct a new 3 element 230 kV ring bus switching station looped into the East Social Circle - East Watkinsville 230 kV Line. Terminate new 230 kV Bostwick - East Walton circuit with 230 kV breakers (at least 1600 A). (See P79137 for the ALP.)

Project Cut-In Date 6/1/2027

Direct Charges	
EC 50 - Construction Contract Labor	\$2,401,356.84
EC 64 - Owner Furnished Material	\$1,945,507.12
Land	\$0.00
Labor (40 & 54)	\$696,566.71
EC 56 - Professional Services	\$348,309.30
Legal	\$4,643.50
Other	\$3,616.53
Project Contingency & Escalation	\$599,999.94
Total Direct Cost	\$6,000,000
Indirect (overheads)	\$1,500,000
Total Project Cost	\$7,500,000
Retired Asset Value	\$0
ITS Investment	\$7,500,000
DSF Investment	\$0
TSF Investment	\$0
Net Change to Facility Investment	\$7,500,000

Assumptions:

1. Estimate based on an analogous estimating approach. McFarland (P89599) used as basis for determining EC values.
2. Contingency costs set at 10% of direct costs. Cost is intended to cover high level nature of planning grade estimates.
3. Indirect cost assumptions include 25% of direct costs.

Planning Grade Estimate

2/1/2023

Project Name: East Walton 500/230 kV Substation
Project Number: P79485
Scope: Construct 500/230 kV S/S. Install 500/230 kV 2016 MVA transformer with an on-site spare phase. (See below for additional scope details. See P78780 for the associated ALP.)

Project Cut-In Date 6/1/2027

Direct Charges

EC 50 - Construction Contract Labor	\$17,100,981.38
EC 64 - Owner Furnished Material	\$11,816,748.46
Land	\$0.00
Labor (40 & 54)	\$2,547,818.64
EC 56 - Professional Services	\$3,281,731.50
Legal	\$296,397.23
Other	\$164,322.79
Project Contingency & Escalation	\$3,911,999.96
Total Direct Cost	\$39,120,000

Indirect (overheads) \$9,780,000

Total Project Cost \$48,900,000

Retired Asset Value	\$0
ITS Investment	\$48,900,000
DSF Investment	\$0
TSF Investment	\$0

Net Change to Facility Investment \$48,900,000

Assumptions:

1. Estimate based on an analogous estimating approach. Raccoon Creek (P75960) used as basis for determining EC values.
2. Contingency costs set at 10% of direct costs. Cost is intended to cover high level nature of planning grade estimates.
3. Indirect cost assumptions include 25% of direct costs.

Planning Grade Estimate

2/1/2023

Project Name: East Walton - Rockville 500 kV Line
Project Number: P79463
Scope: Construct new 46.6 miles of 500 kV line from GTC's new East Walton 500/230 kV S/S to GPC's new Rockville 500 kV S/S (near Wallace Dam) w/ 3-1113 ACSR conductor for 100 degree centigrade operation. (See Project # P78670 for the ALP.)

Project Cut-In Date 6/1/2027

Direct Charges

EC 50 - Construction Contract Labor	\$83,107,573.62
EC 64 - Owner Furnished Material	\$59,183,895.46
Land	\$0.00
Labor (40 & 54)	\$8,846,429.94
EC 56 - Professional Services	\$15,182,801.20
Legal	\$1,370,312.44
Other	\$1,508,987.33
Project Contingency & Escalation	\$18,799,999.81
Total Direct Cost	\$188,000,000

Indirect (overheads) **\$47,000,000**

Total Project Cost **\$235,000,000**

Retired Asset Value	\$0
ITS Investment	\$235,000,000
DSF Investment	\$0
TSF Investment	\$0

Net Change to Facility Investment **\$235,000,000**

Assumptions:

1. Estimate based on an estimate of \$5M per mile provided by Transmission Projects
2. Contingency costs set at 10% of direct costs. Cost is intended to cover high level nature of planning grade estimates.
3. Indirect cost assumptions include 25% of direct costs.

A.1 Rob Patrylak, Managing Partner Curriculum Vitae



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Professional Summary

Rob Patrylak is an innovative and results oriented leader serving as CEO and Managing Partner at Patrylak Energy Advisors. Since starting his career more than 30 years ago, Rob has worked exclusively in the energy industry with a proven track record of delivering a unique combination of technical knowledge and business acumen to deliver innovative and successful business and technical solutions. Rob has worked half of his career directly in the energy industry for either an electric or gas utility (Exelon) or with a risk management and energy trading company (The Energy Authority). He understands the industry from the industry executive or manager perspective. The other half of Rob's career has been leading and providing strategic direction to consulting services organizations such as at Ventyx, Black & Veatch, RW Beck/SAIC/Leidos, Navigant/Guidehouse and now at his own firm, Patrylak Energy Advisors in delivering energy management and technical consulting services as described in his specialization section.

Managing Partner and CEO

Specialization:

Integrated Resource Planning, Energy and Power Market Analysis, RTO Market Design, Risk Management, Regulatory Policy, Strategic Planning, Process Engineering and Design, Capital Planning, Mergers and Acquisitions, Transaction Support & Due Diligence, Grant Application Support Services, Market Assessment & Asset Valuation, Transmission Planning, Expert Witness Testimony

Education

- MBA, Accounting, St. Joseph's University's Erivan K. Haub School of Business
- BS, Mechanical Engineering, Pennsylvania State University

Professional Registration

- Successful completion of Engineer In Training 88, Pennsylvania

Year Career Started

1988

- Integrated Resource Planning
- Capital Planning
- Business Strategy
- Transmission Planning
- Process Engineering and Design
- Energy and Power Market Assessment
- IJIA & IRA project development, evaluation, and funding applications
- RTO/ISO Market Design and Analysis
- Transaction support, Due Diligence, business strategy supporting Mergers and Acquisitions
- Risk management assessing commodity, operational and regulatory risks
- Energy Market Analysis and Asset Valuations acting as a Market Advisor for portfolio and asset transactions
- Software analytics and economic analysis
- Expert Witness Testimony



submit grant application that included engineering and construction package and cost benefit analysis.

Beaches Energy Services (2025) | Strategic Planning, Capital Planning, Grant Support Services – Patrylak Energy Services developed a strategy and approach to pursue a Florida State Grant to harden transmission and distribution circuits in Duval County. Coordinated with Engineering firm, BES Personnel and state agency staff to develop and submit grant application that includes engineering and construction package and cost benefit analysis.

Jacksonville Electric Authority (2024-2025) | Strategic Planning, Capital Budget, IRP, Strategy, Business Excellence – Patrylak Energy Advisors to advise the JEA board of Directors in scrutinizing the city-owned utility's operations and maintenance costs for the electric, water, sewer, utilities and to provide the board with advice on plans to spend billions of dollars on capital projects over the next several years. Patrylak Energy Advisors role will be to review, benchmark and provide recommendations regarding the water/sewer and electric IRP as well as their generation, Transmission and Distribution capital and O&M budgets.

Southern Environmental Law Center (2024) | Strategic Planning, Expert Witness Testimony, RTO Market Design, Transmission, IRP, Strategy – Rob Patrylak served as an expert witness on behalf of the Southern Environmental Law Center (SELC) in response to FERC's briefing order on the Southeast Energy Exchange Market (SEEM). Drawing on his experience in utility regulation and market design, Patrylak provided testimony highlighting the structural flaws in SEEM's design, including the lack of independent governance, transparent price formation, and open access transmission. He emphasized that SEEM's bilateral trading framework favors incumbent utilities and fails to deliver the economic and customer benefits typically seen in organized wholesale markets. His analysis supported SELC's position that SEEM is discriminatory and unlikely to yield meaningful cost savings, recommending that FERC require significant reforms or reject the market proposal outright.

Brownsville Public Utilities Board (2024 -2025; ongoing) | Strategic Planning, IRP, Transmission Planning - Patrylak Energy Advisors is currently developing a comprehensive long-term integrated resource plan (IRP). This strategic partnership underscores Brownsville Public Utilities Board's commitment to ensuring sustainable, reliable, and cost-effective energy solutions for our community.

Confidential Midwest ISO Public Power Agency (2024) | Strategic Planning, IRP, Grant Support Services - Patrylak Energy Advisors developed a financial model to evaluate cost benefit of install 500 residential Tesla batteries using a 3rd party, versus doing it internally versus a utility scale Tesla battery. The financial model addresses all costs and revenue stream, anticipated Grant monies and provides for scenario analysis to assist the client in negotiating and ultimately making an investment decision.

Beaches Energy Services (2024) | Strategic Planning, Capital Planning, Grant Support Services – Patrylak Energy Services developed a strategy and approach to pursue two Florida State Grants: The first project was to raise substation foundation elevation and replace of Substation Transformer, Control House, Switches, etc. The second project was to install a diesel generator. PEA registered on behalf of Beaches Energy Services, managed the 3rd party engineer and utility staff to develop the Grant application and submit it.

Confidential Midwest ISO Public Power Agency (2023) | Strategic Planning, Capital Planning, Integrated Resource Plan -Leveraging a prior resource planning effort performed by our firm, Patrylak Energy Advisors analysed the benefit of adding a 3.5MW solar asset benefitting from the Inflation Reduction Act subsidies. To help with the negotiation, modelled the addition of the asset in a base case scenario, high natural gas, high demand and under a carbon tax future as well as determined breakeven PPA pricing. Analysed the assets individually and combined as well as removing or retiring existing assets that allowed the member to develop a strategy and negotiate the projects. Also provided a range forecast of Renewable Energy Credit revenue associated with the project. –

Confidential Midwest ISO Public Power Agency (2023) | Strategic Planning, Capital Planning, Integrated Resource Plan - Leveraging a prior resource planning effort performed by our firm, Patrylak Energy Advisors analysed the benefit of adding a 4.05MW and 1.25MW solar asset benefitting from the Inflation Reduction Act subsidies. To help with the negotiation, modelled the addition of the asset in a base case scenario, high natural gas, high demand and under a carbon tax future as well as determined breakeven PPA pricing. Analysed the assets individually and combined as well as removing or retiring existing assets that allowed the member to develop a strategy and negotiate the projects.

Confidential Midwest ISO Public Power Agency (2023) | Strategic Planning, Capital Planning, Integrated Resource Plan - Patrylak Energy Advisors advised client regarding Renewable Portfolio Standard legislation and evaluated Renewable Energy Credit pricing for their assets.

Confidential Midwest ISO Public Power Agency (2023) | Strategic Planning, Capital Planning, Integrated Resource Plan - Leveraging a prior resource planning effort performed by our firm, Patrylak Energy Advisors evaluated the retirement and replacement of 8MW generation assets. The resource assessment required working with an engineer to determine cost of retirement, overhaul and new build of existing as well as other alternatives. Both economic and non-economic factors were incorporated into our proprietary decision model to score and rank the best solution.

Confidential Midwest ISO Public Power Agency (2023) | Strategic Planning, Capital Planning, Integrated Resource Plan - Leveraging a prior resource planning effort performed by our firm, Patrylak Energy Advisors analysed the benefit of a 5MW and 3.75MW solar asset benefitting from the Inflation Reduction Act subsidies. To help with the negotiation, modelled the addition of the asset in a base case scenario, high natural gas, high demand and under a carbon tax future as well as determined breakeven PPA pricing. Analysed the assets individually and combined as well as removing or retiring existing assets that allowed the member to develop a strategy and negotiate the projects.

Confidential Midwest ISO Public Power Agency (2023) | Strategic Planning, Capital Planning, Integrated Resource Plan Patrylak Energy Advisors analysed the resources for a 12-member municipal Power Agency under a "Business-as-Usual" reference case and 8 scenarios. We developed financial proformas leveraging the EnCompass software (electric system modelling software) to forecast 25-year revenue and cost streams of system operational costs for the utility. The evaluation compared Net System Operating Cost NPVs of 8 scenarios to the Business-as-Usual Reference Case. Below are the scenarios that were analysed in comparison to the Business-as-Usual Reference Case.

- National Carbon Tax
- High Demand
- High Natural Gas

- Low Demand
- Low Natural Gas
- Low Natural Gas with Carbon Limit
- Zero Carbon Additions

Confidential Midwest ISO Public Power Agency (2021) | Strategic Planning, Capital Planning, Integrated Resource Plan Patrylak Energy Advisors developed a resource planning process and decision tools to provide resource planning capability and analysis to support the organization regarding resource decision making for all 12 members. To accomplish this, Patrylak Energy Advisors solicited bids from production cost modelling and data vendors and oversaw the selection of tools and data. The firm then developed a system model for their power agency and its members and validated the outputs. Having an economic tool in place, Patrylak Energy Advisors then developed a decision-making process to evaluate and select the best solutions encompassing price and non-price factors as well as formats to assist the Power Agency and Members in communicating the results. In the last 30 months, Patrylak Energy Advisors has served as their outsourced resource planning team and have evaluated assets regarding possible retirements, new build fossil, new build solar and procuring PPA for both Energy and Capacity. In total, we have performed approximately 20 studies during that time-period as well as overseen about 5 energy and capacity procurements.

Central Municipal Power Agency and Services Company (2021-2022) | Strategic Planning - Patrylak Energy Advisors facilitated the development of Mission, Vision, Values and Strategic Goals for a Confidential Power Agency and its 12 members. The effort took about a year to complete where Patrylak Energy Advisors facilitated 6-10 board meeting sessions to work through and finalize the effort that was adopted and published.

MEAG Power (2020-2021) | Strategic Planning, Business Process & Re-Design, IT Mapping- Patrylak Energy Advisors has assisted MEAG Power in Procuring and Selecting their existing financial reporting software that is utilized by their Budgets, Accounting and Treasury and Finance departments. The effort scanned 50 software vendors, issuing an RFQ to 14 vendors to short list 4 vendors in developing a proof of concept and workshop to further evaluate and select the successful candidate.

Bay City Michigan (2020-2021) | Strategic Planning, Policy, Procedures - Patrylak Energy Advisors has supported Bay City Michigan in developing power and energy trading strategies as well as developed and Energy Procurement Policy and Energy Procurement Operations Procedure. In addition, performed a market assessment and analysis to determine the capital investment threshold for 4 generation units.

MEAG Power (2020) | Strategic Planning, Business Process & Re-Design, IT Mapping) - Patrylak Energy Advisors developed a Scope, Schedule and Budget for MEAG Power to replace their existing financial reporting software that is utilized by their Budgets, Accounting and Treasury and Finance departments. The effort lays out a framework and roadmap for replacing the existing system over a two-year time horizon.

Bay City Michigan (2021) Generation Resource Assessment – Patrylak Energy Advisors performed a market assessment and retirement analysis to determine the capital investment threshold for 4 generation units. As part of the analysis, determined a breakeven investment point to establish a spending level to extend the asset life.

providing oversight and coordinating the marketing and sales efforts, as well as led and supported various project engagements related to:

- Evaluation of Impacts of Carbon Legislation and RPS
- Project Feasibility Studies
- Market Assessment and Strategy
- FTR Analysis and Strategy
- Wind Curtailment and Integration Strategy
- Renewable Energy Credit Pricing and Strategy
- Economic Transmission Evaluation
- Strategic Resource Planning
- Asset Valuation
- LMP Market Advisory

Ventyx (Following acquisition of New Energy Associates by Ventyx) | 2008

Executive Vice President, Advisors. Responsible for leading and managing the Advisors Business Unit (Consulting) for the Ventyx. Business unit consisting of more than 60 consulting and data professionals. His responsibilities included the \$17M P&L for the business line and encompassed such services as power market assessment, asset valuation, Ventyx reference case products, economic transmission planning, integrated resource planning and Fuel Strategy Advisory. Mr. Patrylak was responsible for the strategic direction of his organization, providing oversight and coordinating the marketing and sales efforts, as well as led and supported various project engagements.

Ventyx, (Following acquisition of New Energy Associates by Ventyx) | 2007–2008

Senior Vice President, Advisors. Lead and managed a 50% growth in consulting services related to the Energy Markets, Strategic Resource Planning, Operations Practice Areas and other consulting expertise with regional responsibility for the Eastern Interconnect (ERCOT, MISO, MRO, SPP, PJM, NYISO, NE-ISO, and SERC). Additionally, led and managed the MarketVision Data Organization supporting the Powerbase suite, which supported PROMOD, Strategist and Market Power. Responsible for a \$6M P&L, Mr. Patrylak provided strategic direction and coordinated marketing and sales efforts, as well as managed and supported various projects related to Market Assessment and Strategy, Asset Valuation, FTR Analysis and Strategy, ISO Cost Benefit Analysis, Wind curtailment and integration strategy, Renewable Portfolio Strategy, Economic Transmission Evaluation, and Strategic Planning. During his tenure, Mr. Patrylak transitioned the NewEnergy Associates/Ventyx consulting organization to a group of industry thought leaders with capabilities to manage large, complex and visible projects such as:

- SPP RTO Market Design Study
- Eastern Wind and Transmission Integration Study
- Nebraska Wind Integration Study
- Midwest Transmission Business Strategy Analysis
- WAPA Wind Integration Study
- OHIO PUC Demand Response/Energy Efficiency Study
- Assisted several MRO companies in strategically analyzing moving to SPP, MISO or remaining in MRO.

merchant transmission facility (\$130M project) for the Long Island Power Authority's 300MW Cross Sound Cable

- Managed or played key roles in more than a dozen merchant generation development project RFP solicitations and subsequent supply contract negotiations (Projects ranged anywhere from \$70M-\$300M) for projects on Long Island
- Managed and led RFP solicitation of a 200-600MW capacity merchant transmission cable between Long Island and the PJM
- Developed business strategy for generation business
- Developed business profiles for new business units
- Performed business/operations assessment for utility for increasing efficiencies & reduced costs
- Oversaw implementation of a major capital spending process
- Supported and managed power supply solicitations
- Performed comparative analysis of the US electric wholesale markets
- Participated in development of business case and strategy for start-up utility
- Oversaw implementation of cost cutting/improved efficiency supply chain initiatives
- Oversaw client participation in an open season process for merchant transmission facilities

PECO Energy Company | 1988–1998

Resource & Project Manager (1997–1998). Managed a regional work team of 160 personnel in a manner that maximized the productivity of field resources in executing the region's work plan. This involved tight coordination of numerous support groups and controls over the scheduled workload to ensure crisp, deliberate hand-offs to the field for execution of work to maximize overall process efficiency.

Re-Engineering Task Force Manager (1997). Responsible for the assessment, re-engineering and documentation of the work management process as part of a six-member task force representing the local Distribution Company. Played a key role in coordinating and leading focus groups consisting of a broad cross-section of individuals across the company. This initiative streamlined the existing process and was successfully implemented in October 1997.

Work Management Supervisor (1997). Managed a group of seven in directing and leading the region's work management process. This included the development of multi-year forecasts and the yearly work plan to support development of the region's capital and operating budget, as well as oversight of the prioritization and scheduling of regional resources to execute the region's workload.

Supervisor of Maintenance Planning (1996–1997). Concurrently, while managing the "RSR Express", Mr. Patrylak led a group of 11 planners and one support person for the Distribution Maintenance Group in overseeing the performance of job planning functions for the region.

Project Manager - Major Capital Projects (1996–1997). Managed a \$5.1 million company-wide Recloser Project known as the "RSR Express." Mr. Patrylak organized, managed, and staffed a

2022 – *“Importance of Reciprocating Engines for Local Reliability” – 3Q 2022*

2019 *“Financing The Energy Transition – Capitalizing on New Investment Opportunities” – 2Q 2019 White Paper*

2017 Mid-Year Navigant Energy Market Outlook – “2017 Mid-Year View of the North American Energy Markets” Webcast Presentation via Energy Central, Sept 2017

ABMA Annual Meeting Presentation – “2017 View of the North American Energy Markets”, June 2017

2017 Navigant Energy Market Outlook – “2017 View of the North American Energy Markets” Webcast Presentation via Energy Central, Jan 2017

2016 Mid-Year North American Energy Market Outlook 2016: Trends and Projections Webcast Presentation, October 2016

EUCI Resource Planning Conference – “Perspectives on States’ Roles in EPA’s Clean Power Plan” Presentation, March 2015

EUCI Resource Planning Conference – “The Clean Power Plan and Potential Impacts on Utility Planning” Presentation, March 2015

GHG Strategies Forum, “Impacts of the Clean Power Plan on the wider Energy Markets, August 2014

2014 Mid-Year Energy Market Outlook and Industry Trends National Webcast Presentation, July 2014

Infocast California Energy Summit – “Impacts of Regional Economics & Load Growth on Energy Costs, May 2014

APPA 2014 Engineering and Operations Technical Conference – “2104 Energy Markets Outlook and Industry Trends”, April, 2014

2014 Energy Market Outlook and Industry Trends National Webcast Presentation, January 2014

2013 Mid-Year Energy Market Outlook and Industry Trends National Webcast Presentation, July 2013

EEI – Strategic Issues Round Table, April 2013 - “Utility Scenario Planning in a Natural Gas World”

B&V Technical Conference – “Energy Market Perspectives - 2013 Energy Market Outlook and Industry Trends”, March 2013

2013 Energy Market Outlook National Webcast Presentation January 2013

“Smart Planning For Utilities”—Solutions Magazine Issue 2, 2012 (June 2012)

2008 EUCI Western Resource Planning Conference, August 2008—*“Wind Feasibility and Transmission Studies”*

2008 Ventyx Forum, March 2008—*“FTR Portfolio Analysis”*

2008 EUCI Resource & Supply Planning Conference, January 28-29, 2008—*“Designing and Implementing an RFP for Power Supply Needs”*

2006 NewEnergy Associates Forum, March 2006—*“Industry Trends in Energy Markets”*

2006 IEEE PES General Meeting, June 2006—*“Valuation Approaches for Financial Transmission Rights”*

Total Portfolio Cost Estimates (Present Value Revenue Requirements (PVRR) or Net Present Value (NPV))								
	GPC 2025 IRP	Dominion Virginia 2024 IRP	DESC 2025 IRP Update	Santee Cooper 2024 IRP Update	DEC/DEP Combined 2023 Resource Plan	LG&E and KU 2024 Joint IRP	I&M Power 2024 Indiana IRP	TVA 2025 Draft IRP Update
	Ex. 2A	Ex. 2D	Ex. 2E	Ex. 2F	Ex. 2G	Ex. 2H	Ex. 2I	Ex. 2J
Planning Scenario		(NPV) (\$B)	(LNPV) (\$M)	(NPV)(\$B)	(PVRR)(\$B)	(PVRR)(\$ M)	(NPVRR) (\$B)	(PVRR) (\$B)
1		100.2	2.630	29.3	139	13,657	32	154
2		93.7	2.393	29.2	124	-	39.3	191
3		102.9	2.407	35.7	119	-	25.7	130
4		97.0	2.399	-	-	-	33.2	184
5		-	2.519	-	-	-	33.3	228
6		-	-	-	-	-	41.4	156
7		-	-	-	-	-	39.9	-
8		-	-	-	-	-	34.9	-
9		-	-	-	-	-	28.3	-
10		-	-	-	-	-	32.1	-
11		-	-	-	-	-	32.6	-
12		-	-	-	-	-	32.4	-
13		-	-	-	-	-	31.8	-
14		-	-	-	-	-	32.8	-
15		-	-	-	-	-	34.8	-

Table 2: Comparing high-level cost estimates of system upgrades disclosed by utilities in recent IRPs.
This table is not for directly comparing the cost of upgrading the system but rather the type of information disclosed.

Large Load Forecasts							
	GPC 2025 IRP 	Santee Cooper 2024 IRP Update 	Dominion Virginia 2024 IRP Supplement ¹ 	DEC 2023 Carolinas Resource Plan 	DEP 2023 Carolinas Resource Plan 	LG&E and KU 2024 Joint IRP 	I&M Power 2024 Indiana IRP 
	External Peak Adjustments for Large Loads	Forecasted System Energy Sales Potential Large Load Customers (GWhs)	Data Center Annual Energy Forecast (GWhs)	Adjustments in Load Forecast for Large Site Developments (MWh)	Adjustments in Load Forecast for Large Site Developments (MWhs)	Data Center Load Forecast Scenarios (MWs)	Forecasted New I&M Hyperscaler Loads by PJM Planning year (MWs)
2024		0	0	139,023	-	-	-
2025		0	1,546	711,032	525,627	-	-
2026		752	6,815	1,016,318	946,087	-	750
2027		2,017	9,566	1,504,031	1,288,761	-	1,350
2028		3,327	12,793	2,122,049	1,723,534	-	1,900
2029		4,629	16,103	2,931,801	2,120,269	-	2,050
2030		6,435	19,555	3,518,174	2,402,781	-	4,350
2031		7,705	22,938	4,104,546	2,765,064	-	4,350
2032		8,826	27,067	4,690,919	2,892,107	Low: 0 Mid: 1,050 High: 1,750	4,350
2033		9,215	31,169	5,277,291	2,892,107	-	-
2034		9,215	35,894	5,863,664	2,892,107	-	-
2035		9,215	40,992	5,863,664	2,892,107	-	-
2036		9,215	46,456	5,863,664	2,892,107	-	-
2037		9,215	52,205	5,863,664	2,892,107	-	-
2038		9,215	58,411	-	-	-	-
2039		9,215	64,670	-	-	-	-
2040		9,215	-	-	-	-	-

Table 3: Comparing utilities' disclosures related to the impact of large loads on forecasted demand. This table is not intended to directly compare the size or methodologies of large load forecasts, but instead reflects the type of information disclosed.

¹ These numbers reflect the difference between the energy (GWh) for Dominion's 2024 IRP projections with and without data center growth, as reflected in "SCC Directed 2024 IRP Supplement Figure 2.1.1."

STF-NHSW-6 - Generic Resource Comparison

Exhibit STF-NHSW-6
Generic Resource Comparison
REDACTED

Combined Cycle																
	GPC 2025 IRP	GPC 2023 IRP Update	LG&E/KU 2024 IRP	LG&E/KU CPCN	LG&E/KU CPCN	Santee Cooper 2024 IRP Update		DESC 2025 IRP Update	EIA AEO 2025	Lazard 2024 LCOE	Lazard 2024 LCOE	NREL ATB 2024	Entergy NOLA 2024 IRP	Ind. Mich. Pwr Comp. 2024 IRP	Duke Energy Indiana 2024 IRP	Duke Indiana CPCN
	NGCC 1x1		NGCC	Brown 12	Mill Creek 6	1x1 H Class	1x1 F Class	1x1 Greenfield	Single- Shaft	(Low) (New Build)	(High) (New Build)	H Frame				Cayuga CC
Year Availability			2030	2030	2031	2031	2031		2027					2031	2030	
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)			660	660	660	630	357	665	627	550	550	649	729	420	719	1,476
Capital Cost (\$/kW)			2,121	2,120	2,138	1,949	3,010	2,337	1,003	974	1,490	1,752	1,520	1,955	1,662- 1,777	2,597
Fixed O&M (\$/kW-yr.)			7.80	7.80	7.10	8.91	13.47		18.05	11.46	29.23	46.78	14.75	19		
Variable O&M (\$/MWh)			0.23	0.23	0.23	3.27	3.78		3.89	3.15	5.73	3.00	5.83	3		
Average Heat Rate (MBTU/MWh)			6,300	6,300	6,300	6,136	6,668		6,226	6,750	7,500	6,068	6,759	6,430		

Exhibit STF-NHSW-6
Generic Resource Comparison
REDACTED

Solar													
	GPC 2025 IRP	GPC 2023 IRP Update	Santee Cooper 2024 IRP Update	Duke Energy Indiana 2024 IRP	DESC 2025 IRP Update	EIA AEO 2025	NREL ATB 2024 (Mod)	Entergy NOLA 2024 IRP	Lazard 2024 LCOE (Low)	Lazard 2024 LCOE (High)	TVA Draft 2025 IRP	LG&E/KU Utility- Scale Solar 2024 IRP	Indiana Michigan Power Company 2024 IRP
Year Availability	2028	2027	2026	2027		2026					2027		2028
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)			50	50	100	150	100	100	150	150	50	100	150
Capital Cost (\$/kW)			1,781	2,120	1,826	1,581	1,654	2,188	974	1,605	1,490	1,902	2,616
Fixed O&M (\$/kW-yr.)			27.30			26.26	26.39	15.36	12.61	16.05		17.00	10.04

Battery Storage (4 Hour)											
	GPC 2025 IRP	GPC 2023 IRP Update	Santee Cooper 2024 IRP Update (4 Hour)	Duke Energy Indiana 2024 IRP (4 Hour)	DESC 2025 IRP Update (4 Hour)	EIA AEO 2025 (4 Hour)	NREL ATB 2024 (Mod) (4 Hour)	Entergy NOLA 2024 IRP (4 Hour)	TVA Draft 2025 IRP	LG&E/KU 2024 IRP (4 Hour)	Indiana Michigan Power Company 2024 IRP (4 Hour)
Year Availability	2028		2026	2028		2025			2029	2028	2028
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)			50	50	100	150	60	50/200	50	100+	50
Capital Cost (\$/kW)			2,132	2,636	2,281	1,811	2,123	2,734	1,656	2,049	2,093
Fixed O&M (\$/kW-yr.)			53.29			46.56	52.78	17.34	53.42	25.00	54.57

Estimated Cost of Transmission Projects Under Construction, Planned, and Proposed ¹						
	GPC 2025 IRP	Dominion Virginia 2024 IRP	Duke Energy	I&M Power 2024 Indiana IRP	DESC	Carolinas Transmission Planning Collaborative
		Ex. 8C	Ex. 8D	Ex. 8E	Ex. 12	Ex. 13
Project		(\$M)	(\$M)	(\$M)	(\$M)	(\$M)
1		0.3	19.75	5.0	5.40	8.0
2		0.5	8.52	7.0	5.30	38.0
3		51.9	29.11	13.0	11.12	12.0
4		151.0	27.74	47.0	19.89	93.0
5		0.8	54.47	33.0	11.70	13.0
6		42.0	54.47	50.0	8.58	16.0
7		5.0	-	7.0	6.93	63.0
8		13.9	-	11.0	4.91	14.0
9		3.0	-	46.0	48.22	29.0
10		4.5	-	30.0	40.66	103.0

Table 8: Comparing disclosures of high-level cost estimates for transmission projects. This table is not for directly comparing the cost of specific projects but rather shows which utilities provide cost information in transmission planning.

¹ This table shows a sample of the disclosed cost estimates for transmission projects. For a complete list of each utilities' transmission projects, see the exhibits associated with each utility.

² Exhibit 12 contains one example from Dominion Energy South Carolina's Regional Transmission Planning documents. For the full list of DESC projects displayed in this table, see Dominion Energy South Carolina Planned Transmission projects \$2M and above Total 5 Year Budget.