Page 2, Line 16 through the word “Second,” on Page 3, Line 14

professional resume, which includes my employment history, education, and history of commission and similar hearings, is attached as Exhibit JW-1 to this testimony.

Q: HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?

A: Yes. I have testified more than eighty times before utility regulators in twelve U.S. states and Nova Scotia and appeared numerous additional times before various regulatory and legislative bodies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A: Yes. I have testified seven times before this Commission, as listed in the attached resume.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: Georgia Interfaith Power and Light (GIPL), and its member congregations Park Avenue Baptist Church, Temple Sinai, and Unitarian Universalist Church of Savannah.

FINDINGS AND RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A: I have two sets of recommendations for the Commission. First, I find that Georgia Power has set its RTP price too low during peak hours because the reliability cost component was set inconsistently with the peaker method. Accordingly, I recommend that the Commission direct Georgia Power to:

1. File its method for calculating the transmission and reliability cost component prices in the rate case docket, with full details on the source(s) of market value data and how the prices are to be calculated. If the Commission has concerns that either

calculation method is inconsistent with prior orders or otherwise potentially adverse to the interests of other customers, it should direct further proceedings as appropriate.

2. File its annual update of RTP transmission and reliability cost component prices as a compliance filing in the rate case docket with evidence demonstrating how it has followed the Commission-approved method.
3. If Georgia Power seeks to make changes to the method, file the proposed revised method at least 60 days prior to its annual update so that the Commission has an opportunity to review that change and determine if further proceedings are necessary prior to the update becoming effective.

Furthermore, I also suggest that the Commission should direct Georgia Power to engage with its Staff and intervenors to reconsider the appropriateness of the design of its transmission and reliability cost components.

Second, I find that several categories of costs recovered from FCR customers are not included in the RTP fuel credit. The RTP fuel credit – on a $/MWh basis – is therefore an underestimate of the fuel costs that should be allocated to the incremental load priced at RTP. Accordingly, I make several recommendations for changes to the RTP fuel credit, including that the Commission should:

4. Adopt Georgia Power's recommendation to "exclude both the costs and the output from non-dispatchable PPAs in the RTP fuel credit calculation."

Page 4, Line 18 through Page 5, Line 2

5. Adopt, with modifications, Georgia Power's recommendation to recover the costs of new firm transportation (FT) cost from large load customers, excluding those costs from the FCR rate.
6. Revise the RTP fuel credit calculation to include direct contributions to FT cost, assuming fixed fuel delivery costs are not included in the marginal value of generation capacity. If that is not the case, then I provide two alternate recommendations whereby the Commission should either allocate FT costs to RTP customers in the fuel docket or move FT costs to base rates.
7. Reject Georgia Power's proposal for a winter 1CP allocation of new FT cost, instead using the same allocation factor as transmission costs until the issue is fully examined in the next rate case. To the extent that the Commission seeks to rely on Georgia Power's large load cost model, the Commission should also direct Georgia Power to make a working copy available to intervenors on a basis that addresses commercial sensitivity concerns yet allows for full stakeholder participation in Commission decisions based wholly or in part on that model.
8. Revise the RTP fuel revenue credit to include coal-related costs and corporate overhead and labor.

Furthermore, I suggest that, in the next rate case, the Commission consider updating the RTP rate design to also include corporate overhead and labor as well as FT, coal-related, and other fixed fuel delivery costs if it is determined that the reliability cost component of the RTP rate does not include these costs. This could be simply accomplished by updating

the recovery factor. I also draw to the Commission's attention the effect of including large load growth in the hedging cap approved as part of the FCR-27 settlement.

BACKGROUND

Q: WHY IS THE COMMISSION REVIEWING THE RTP REVENUE ALLOCATION METHODOLOGY?

A: In the last few years, the Commission has approved the procurement of thousands of megawatts of new generation resources to accommodate large load customers. Given the magnitude of the billpayer investments forecasted by Georgia Power, the Commission has treated these large loads in a distinct manner, holding them to a higher standard when it comes to cost shifting. The FCR-27 proceeding was the first fuel proceeding since the data center boom began and parties raised concerns that the current RTP methodology, which has been applied to data center customers, resulted in higher fuel costs for other customers, in apparent contravention of Georgia Power's statements that data centers would not be subsidized by existing customers.

Q: IS THE STANDARD FOR LARGE LOAD CUSTOMERS LIKE DATA CENTERS DIFFERENT THAN FOR OTHER RTP CUSTOMERS?

A: Yes. The Commission has ordered Georgia Power to "protect existing customers from bearing any of the costs of adding these large customers."[1] The Commission has further ordered Georgia Power to "file its next base rate case in a manner that will ensure the incremental revenue from large load customers has downward pressure … to the typical

[1] Order on Georgia Power Company's Revision to Rules and Regulations Tariff Compliance Filing, Dkt. 44280 (April 17, 2025).

Page 12, Line 13 through Page 17, Line 14

A: Table 1 shows RTP revenue by rate component for 2023, with the revenue from lambda further split into the RTP fuel credit and the revenue contribution for generation variable O&M and capital substitution.

Table 1: 2023 RTP Revenue by Rate Component[13]

	$ (millions)	Percent
Lambda: RTP Fuel Credit	[redacted]	[redacted]
Lambda: O&M / Capital Substitution		
Recovery Factor		
Transmission Cost		
Reliability Capacity Cost		
Total Revenue		

However, the total revenue based on this calculation differs from the $740.0 million total provided in another discovery response.[14]

Q: HOW WELL DOES THIS ALIGN WITH GEORGIA POWER'S FORECAST OF 2023 REVENUE IN ITS 2022 RATE CASE?

A: Based on the response to GIPL Hearing Request No. 1 and data from the 2022 rate case, the capital substitution from the lambda rate component for the test year ending July 31, 2023 was forecast to be $158.3 million, the transmission cost was forecast to be $33.6 million, and the reliability capacity cost was forecast to be $21.7 million.[15]

Q: PLEASE EXPLAIN HOW GEORGIA POWER CALCULATES THE MARGINAL VALUE OF GENERATION CAPACITY.

[13] Calculated from Georgia Power's Trade Secret Attachments to STF-JKA 3-5, JKA-3-8, and JKA-8-7 in Docket 56765.
[14] Georgia Power's Response to STF-JKA-4-6 Attachment, Dkt. 56765 (March 30, 2026).
[15] Direct Testimony of Lee Evans on behalf of Georgia Power Company, Exhibit LPE-2, Dkt. 44280 (June 24, 2022).

A: From 2020 to 2024, Georgia Power used the "[redacted]"[16]

However, Georgia Power deviated from this approach in 2023, 2024, and 2025:

- In 2023, Georgia Power disregarded the [redacted].[17]
- In 2024, Georgia Power again justified deviations from its prior approach [redacted].[18]
- In 2025, Georgia Power changed to a different data source for the capacity value, [redacted].[19] Again, Georgia Power used a [redacted]

[16] Georgia Power's Response to STF-JKA-10-11 Attachment A TRADE SECRET, Dkt. 56765 (July 14, 2026).
[17] *Id.*
[18] *Id.*
[19] Circumstantial evidence suggests that [redacted] *Id.* Attachments A and G TRADE SECRET.

[redacted]

[redacted].[20]

Q: WHAT SPECIFIC COSTS OF NEW GENERATION CAPACITY ARE INCLUDED IN GEORGIA POWER'S MARKET VALUE ESTIMATES?

A: This information was not provided by Georgia Power. For example, it is unclear whether these costs would include firm transportation delivery costs for natural gas or costs related to coal quality and delivery (e.g., rail cars) if the market value were determined by a gas or coal unit. Similarly, if the market value is based on a battery storage unit, consideration might (or might not) be given to charge cycle losses, degradation, and other costs that may be viewed as either fixed or variable. This is relevant because it remains unclear exactly what fixed costs are included in Georgia Power's marginal value data.

Q: IS GEORGIA POWER'S RECENT METHOD FOR CALCULATING THE VALUE OF CAPACITY FOR THE RELIABILITY COMPONENT OF THE RTP RATE CONSISTENT WITH THE PEAKER METHOD?

A: No. In 2023, 2024 and 2025 Georgia Power charged RTP customers a significantly lower price than its contemporaneous data for the marginal cost of capacity. Georgia Power's justification that capacity prices were driven by [redacted] was demonstrated, in hindsight, to be flawed. In Table 2, I compare the Trade Secret market-derived capacity value with the reliability cost used by Georgia Power to, in combination with a loss factor, determine the reliability price used for the reliability component of the RTP Rate.

[20] *Id.* Attachment A TRADE SECRET.

Table 2: Value of Capacity vs RTP Reliability Cost Component, 2023-2025[21]

	Value of Capacity ($/kW-Yr)	Reliability Price ($/kW-Yr)	Reliability Cost ($/kW-Yr)
2023	[redacted]	[redacted]	[redacted]
2024			
2025			
Average			
Variation			

Over these three years, the market value of capacity was much higher than the reliability cost included in RTP rates for each year. Furthermore, the market value showed much more stability than Georgia Power's "reliability cost."

Thus, while the RTP rate is intended to encourage "usage when the marginal unit cost is lower and discouraging usage when that cost increases,"[22] in fact Georgia Power set the RTP rate so low that it encouraged more usage than it should have.

Q: COULD AN UNREASONABLY LOW RTP RATE ENCOURAGE EXCESS DEMAND?

A: Yes. A well-informed customer with visibility into Georgia Power's historical RTP rates during 2023-2025 could form an unreasonable expectation that the RTP rates during peak hours appear to be lower than market conditions might suggest, and could then proceed to make both short-term operational decisions and long-term investment decisions based on these incorrect prices.

Q: IS A [redacted] OF CAPITAL COSTS A MARGINAL COST CALCULATION?

[21] *Id.*
[22] GPC Direct Testimony at 8:3-4.

A: No. A [redacted] cost is closer to [redacted]. Georgia Power's [redacted] method – which [redacted] – does appear to be a reasonable basis for market price data. A marginal capacity cost cannot be measured in a single hour as is done for lambda. But, as shown in Table 2 above, a [redacted] can persistently misrepresent the current market price for generation capacity.

Q: WAS THE COMMISSION OR STAFF INFORMED AS TO THESE DECISIONS BY GEORGIA POWER?

A: The evidence I have reviewed includes no suggestion that Georgia Power informed the Commission or Staff as to its pricing decisions, or considered any views other than its own in deciding how to set the reliability component of the RTP rate.

Q: HOW COULD OTHER CUSTOMERS BE AFFECTED BY THIS PRICING STRATEGY?

A: Setting the RTP price too low during peak hours can affect other customers through both effects on RTP customer demand and on revenue forecasts during rate cases.

Q: HOW CAN SETTING THE RTP PRICE TOO LOW DURING PEAK HOURS IMPACT RTP CUSTOMER DEMAND?

A: Setting the RTP price too low during peak hours sends an improper price signal to RTP customers, resulting in more energy use than would occur with an accurate RTP price signal. In theory, RTP customers pay for this increased energy use through the RTP fuel revenue credit, as discussed below. But as also discussed below, RTP customer energy use can affect either the amount or the cost allocation of certain "fixed" fuel-related costs that

are included in the FCR; thus, uneconomically high RTP customer energy use can drive up fuel costs for other customers.

Q: HOW CAN SETTING THE RTP PRICE TOO LOW DURING PEAK HOURS AFFECT RTP CUSTOMER REVENUE FORECASTS DURING RATE CASES?

A: In a rate case, test year costs are compared to test year revenues. If the RTP price is set too low during a year that is used as a test year during a rate case, then system revenues will be depressed. This will tend to drive up rates.

To some extent, this may be mitigated for non-RTP customer classes since the classes with RTP customers presumably would show a greater revenue deficiency. But as Georgia Power's testimony states, RTP rate design is intended to "ensure[] that the expected revenues more than cover the incremental costs to serve new load."[23] But if the RTP rates are set too low, as suggested in Table 2, then the actual revenues will not cover those incremental costs – and thus recovery of those costs will be shifted to other customer classes.

Q: ARE CHANGES TO RTP RATE DESIGN WITHIN THE SCOPE OF THIS PROCEEDING?

A: No. Nonetheless, I recommend that Georgia Power propose for Commission review and approval RTP pricing that utilizes [redacted] as quickly as possible.

Q: WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

[23] GPC Direct Testimony at 10:5-6.

Page 17, Line 17 beginning at “Nonetheless,” through Page 19, Line 17

are included in the FCR; thus, uneconomically high RTP customer energy use can drive up fuel costs for other customers.

Q: HOW CAN SETTING THE RTP PRICE TOO LOW DURING PEAK HOURS AFFECT RTP CUSTOMER REVENUE FORECASTS DURING RATE CASES?

A: In a rate case, test year costs are compared to test year revenues. If the RTP price is set too low during a year that is used as a test year during a rate case, then system revenues will be depressed. This will tend to drive up rates.

To some extent, this may be mitigated for non-RTP customer classes since the classes with RTP customers presumably would show a greater revenue deficiency. But as Georgia Power's testimony states, RTP rate design is intended to "ensure[] that the expected revenues more than cover the incremental costs to serve new load."[23] But if the RTP rates are set too low, as suggested in Table 2, then the actual revenues will not cover those incremental costs – and thus recovery of those costs will be shifted to other customer classes.

Q: ARE CHANGES TO RTP RATE DESIGN WITHIN THE SCOPE OF THIS PROCEEDING?

A: No. Nonetheless, I recommend that Georgia Power propose for Commission review and approval RTP pricing that utilizes [redacted] as quickly as possible.

Q: WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

[23] GPC Direct Testimony at 10:5-6.

A: It appears that Georgia Power has exercised what can charitably be described as exceptionally broad discretion in determining the reliability price component of the RTP rate. These decisions have potentially already harmed other customers. Accordingly, the Commission should direct Georgia Power to take the following steps.

First, Georgia Power should be directed to file its method for calculating the transmission and reliability cost component prices in the rate case docket, with full details on the source(s) of market value data and how the prices are to be calculated. If the Commission has concerns that either calculation method is inconsistent with prior orders or otherwise potentially adverse to the interests of other customers, it should direct further proceedings as appropriate.

Second, the Commission should require Georgia Power to file its annual update of RTP transmission and reliability cost component prices as a compliance filing in the rate case docket with evidence demonstrating how it has followed the Commission-approved method. This would be similar to its annual avoided cost filing.

Third, if Georgia Power seeks to make changes to the method, it should be required to file its revised method at least 60 days prior to its annual update so that the Commission has an opportunity to review that change and determine if further proceedings are necessary prior to the update becoming effective.

Q: DO YOU HAVE OTHER COMMENTS ON THE TRANSMISSION AND RELIABILITY COST COMPONENTS?

A: Yes. I suggest that the Commission should direct Georgia Power to engage with its Staff and intervenors to reconsider the design of its transmission and reliability cost components.

While the basic design of those components is sound – allocating generation and transmission costs over multiple hours based on load and, in the case of transmission, temperature, since Georgia Power developed this method, there have been advances in other jurisdictions that could inform an improved RTP design.

In a case involving the design of a real-time pricing rate for Pacific Gas & Electric (PG&E), I represented small business interests in identifying flaws in its proposed rate design. PG&E accepted my critique, and engaged in a multi-party rate design study that resulted in an improved proposal, which was accepted by the California Public Utilities Commission.

Keeping it very simple, that design involved allocating capacity costs over many hours of the year, but using an "S-shaped" curve that set capacity prices relatively low when net demand was low, and then escalated sharply as demand began to reach high levels, only to mostly level off at the highest levels.

Replicating the same design in Georgia may or may not be a good match for the different circumstances, but some of the key lessons do apply. The RTP capacity price signal was explicitly designed to be closely aligned with grid stress as experienced on the PG&E system. This is very much the definition of a cost-based rate design.

RTP FUEL CREDIT

Q: WHAT IS THE RTP FUEL CREDIT?

A: The RTP Fuel Credit is the process for recording a portion of revenues from incremental load priced at RTP as a credit in the FCR. In other words, FCR customers pay all fuel costs net of the RTP Fuel Credit. The RTP fuel credit is currently calculated as follows:

Page 27, Lines 9-16

Q: WHAT ALTERNATIVE TO THE WINTER 1CP COST ALLOCATION METHOD DO YOU PROPOSE?

A: Since FT is similar to transmission, in that it is required to meet peak demand conditions whenever and for whatever reason they may occur, I recommend that new FT costs be allocated between large load customers and other growth using the same allocation factor as transmission costs. This decision could be made explicitly provisional until the next rate case when a full review of cost allocation methods relevant to large load customers can be considered.

Q: WHAT FURTHER STEPS SHOULD THE COMMISSION TAKE TO ALLOW FOR A FULL REVIEW OF THIS ISSUE IN THE NEXT RATE CASE?

A: I recommend that the Commission direct Georgia Power to make a working copy of its large load cost model available to intervenors in this proceeding on a reasonable and protected basis so that I and other experts can be prepared to advise our clients and the Commission on related cost allocation questions. Speaking for myself, I have a clear understanding of the commercial sensitivity of this information and have a well-established track record of maintaining appropriate protection of Georgia Power's trade secrets.

Q: ARE THERE OTHER FCR COST CATEGORIES WHOSE TREATMENT FOR RTP CUSTOMERS SHOULD BE REVISED?

A: Yes. The RTP fuel credit "does not incorporate fixed fuel costs, which do not vary with changes in demand."[35] However, while I agree that these costs are not truly "marginal" in

[35] GPC Direct Testimony at 13:4-5.

Page 30, Line 14, beginning at “However,” through Page 31, Line 11

an RTP fuel credit value based on average annual or monthly costs on a per kWh basis, increasing the RTP fuel credit correspondingly.

While this may not represent a perfect credit for the RTP customer share of these costs, it should be reasonably close. Over time, if it is shown that there is material variation in this portion of the RTP fuel revenue credit and actual cost recovery from these customers (as compared to a per kWh cost allocation of these costs on an annual basis), then this method should be reconsidered, as the Commission has done before with the RTP fuel credit.

This will not result in double-recovery, as the rates charged to RTP customers will not change, just the RTP fuel revenue credit. But it will shift revenue credit from base rates to FCR. This will assist in reducing FCR rates for FCR customers, but may increase base rates for those same customers, depending on how other cost allocation questions are handled.

Q: ARE YOU RECOMMENDING ANY CHANGES TO THE RTP RATE ITSELF IN THIS PROCEEDING?

A: No, that is out of scope in this proceeding. However, the Commission should consider updating the recovery factor to also include corporate overhead and labor as well as FT, coal-related, and other fixed fuel delivery costs if it is determined that the reliability cost component of the RTP rate does not include these costs. For comparison with Table 1 values above, the 2025 corporate overhead and labor cost allocated to FCR was $5.7 million.[38]

Q: WHAT COSTS ARE CURRENTLY INCLUDED IN THE RECOVERY FACTOR?

[38] Georgia Power's Response to STF-JKA-3-6 Attachment PUBLIC DISCLOSURE, Dkt. 57171 (Sept. 3, 2026).

A: As noted above, in its decision in 2000, the Commission stated that the recovery factor (then referred to as an "adder") provides Georgia Power profit and compensation for the risk that advance quotes of RTP prices understate actual prices (potentially resulting in FCR costs that are not recovered from RTP load).[39] In a motion filed by Georgia Power in response to that decision, Georgia Power also stated that the recovery factor "lessens the need to collect for clean air and commitment costs" as well as indirect effects on other costs, and thus it compensates FCR customers for costs that "are not included in the RTP price."[40]

As the recovery factor has not been updated since 2000, it would be appropriate for Georgia Power to identify all costs that may not be recovered through the RTP and propose an update to the recovery factor in the next rate case.

Q: WHAT FCR COST CATEGORIES SHOULD CONTINUE TO BE EXCLUDED FROM THE RTP FUEL CREDIT METHODOLOGY, AND WHY?

A: I support excluding fuel-related costs that are not actual costs of fuel (or purchased power) used to generate electricity. This includes gas hedging gains/losses, gas gains/losses on resales, FCR carrying costs, and net renewable program revenues/expenses.

My rationale is that the fuel component of RTP rate revenues should be designed to cover all actual costs of fuel. Costs related to hedging and resales are intended to reduce fuel cost volatility through either financial or physical hedges.

[39] Order, at 6, Dkt. 11708-U In re: Petition for Rule Nisi to Examine Georgia Power Company's Real Time Pricing Structure (May 12, 2000).
[40] Georgia Power Company's Motion for Reconsideration, at 7-8, Dkt. 11708-U (June 22, 2000).

Page 33, Line 3 through Page 34, Line 2

Finally, with respect to the net renewable program, under the FCR-27 stipulation, these costs are no longer recovered through the fuel clause and thus the issue is moot.[43]

Q: HOW DOES LARGE LOAD GROWTH AFFECT GEORGIA POWER'S HEDGING COSTS INCLUDED IN THE FCR RATE?

A: As noted above, as a result of the settlement in FCR-27, Georgia Power's hedging is capped at 20% of total forecasted methane gas fuel burn. As large load growth impacts Georgia Power's fuel use forecast, it also drives up the amount of hedging, whether physical or financial.

For example, without large load customer demand, Georgia Power would hedge 20% of FCR gas fuel burn. If large load customer demand is forecast to increase total gas fuel burn by 50% for a given period, then hedging would increase proportionately. The result would be an effective increase in the FCR gas fuel cost hedging cap from 20% of FCR gas fuel burn to 30%.

This is not a "cost" necessarily caused by large load demand and imposed on FCR customers, although it has resulted in a cost increase for non-large load customers in FCR-27. Rather it is the effect of the hedging cap design which applies to all gas fuel consumption rather than just consumption forecast to meet FCR customer demand.

While revisiting this issue may be outside the scope of this proceeding, I draw it to the Commission's attention as it is appropriate to exclude load served by RTP customers from the costs and benefits of managing fuel price volatility, and thus it may also be appropriate

[43] Georgia Power's Response to STF-JKA-3-6, Dkt. 57171 (Sept. 3, 2026).

to exclude that load from the limit on gas hedging, particularly in light of the Commission's rules regarding large load cost shifting.

Q: YOU HAVE NOT DISCUSSED THE INCOME-QUALIFIED DISCOUNT (IQD). DO YOU HAVE A POSITION ON HOW THE COSTS OF THIS PROGRAM SHOULD BE TREATED FOR RTP CUSTOMERS?

A: It is my understanding that costs of the IQD are primarily collected in base rates, but that a fuel-related portion of the cost is collected in the FCR. It is not clear whether the Commission has considered how to fairly recover IQD costs from incremental load served by RTP customers. A customer taking service on an RTP rate would pay less than the same customer taking service on a non-RTP rate. Certainly it cannot be argued that IQD costs are included in lambda or any concept of capital substitution under the peaker theorem. Resolving this is therefore not a matter of whether these costs should be included in the RTP fuel revenue credit, since these costs are not currently accounted for anywhere in the RTP rate. Given that rates have been set that do not collect IQD costs from incremental RTP load, I do not take a position on this category of costs in this proceeding.

However, I suggest that the Commission direct or that Georgia Power voluntarily agree to develop a fair and reasonable method for allocating a portion of IQD costs to RTP and/or large load customers. The most straightforward method would appear to be a further adjustment to the recovery factor, in addition to those suggested earlier in my testimony, with appropriate allocation of those revenues to both the RTP fuel revenue credit and the balance credited to base rate revenues.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.