BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

Capacity and Energy Payments to Cogenerators Under PURPA	Docket No. 4822
Georgia Power Company's Green Energy Program	Docket No. 16573
Biomass Gas & Electric, LLC's Petition to Establish Docket Regarding Forsyth County Renewable Energy Plant	Docket No. 19279

REBUTTAL TESTIMONY OF
JOHN D. WILSON
ON BEHALF OF GEORGIA LARGE SCALE SOLAR ASSOCIATION

December 4, 2020

TABLE OF CONTENTS

ATTACHMENTS

Exhibit JDW-4	*Standard Contract for the Purchase of Rated Capacity and Energy From a Qualifying Facility (Red Line Version)*
Exhibit JDW-5	*Marginal Cost Multiplier (Trade Secret Excel Workbook)*

I. Identification & Introduction

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Did you previously present direct testimony on behalf of Georgia Large Scale Solar Association in these proceedings?

A: Yes.

Q: What is the purpose of your rebuttal testimony?

A: This rebuttal testimony updates my direct testimony in response to Georgia Power's direct testimony and its responses to staff data requests. In addition to updating my proposed modifications to Georgia Power's current application of its avoided costs and the methodologies to calculate those avoided costs for QFs, I am also proposing a new standard offer contract.

Q: What issues do you address?

A: I am addressing six issues. First, I am updating my evaluation of the fuel cost component of Georgia Power's projected avoided energy costs to reflect additional information regarding commodity charges that are incurred in the delivery of natural gas to its power plants. Second and third, I am updating my review of the fuel cost multiplier and the marginal cost multiplier components of Georgia Power's projected avoided energy costs, which do not appear consistent with the Commission's 1994 Order. Fourth, Georgia Power's avoided capacity resource is unnecessarily restricted to years with a capacity need identified in the IRP. Georgia Power can derive benefit from capacity supplied by QFs in advance of the need identified in the IRP. Fifth, I review Georgia Power's calculation of the cost of new capacity. Sixth, I review the new proposed standard offer contracts to determine if their structures allow for adequate and appropriate compensation to PURPA Qualified Facilities (QFs).

Q: What modifications do you recommend to Georgia Power's current avoided cost methodologies?

A: The Commission should direct Georgia Power to:

- Fully examine fixed transportation and storage costs to determine if any of the costs are misclassified as fixed;
- Develop an avoided storage withdrawal cost which would be available to battery storage and other similar resources, potentially as a modification to the RCB Framework;
- Provide a plant-specific comparison of commodity contract terms with historical and forecast variable cost data to demonstrate full alignment;
- Continue use of the fuel cost multiplier (denying the Company's request to eliminate it), updated to reflect all financial instruments that the Company is using to manage fuel contract costs;
- Utilize the fuel cost multiplier in all forecasts of avoided energy costs;
- Continue use of the marginal cost multiplier (denying the Company's request to eliminate it);
- Revise the avoided cost method to apply the fuel cost and marginal cost multipliers to the startup and commitment cost adder;
- Calculate avoided capacity cost based on the Company's forecast reserve margin, thus adding a "discount" avoided capacity cost to QF rates in order to capture "extraordinary advantage" opportunities that may occur;
- Determine the avoided cost of capacity associated with the retirement of Plant Wansley units 1 and 2 for possible inclusion in the avoided capacity cost;

- Use a transparent, publicly-available Southeast-specific value from the US Energy Information Administration (EIA) for the ECC of a CT when setting avoided capacity cost;
- Study the impact of a shorter lifetime for gas-fueled generation units on capacity cost in the next integrated resource planning proceeding;
- Offer a QF Rated Capacity and Energy PPA standard offer contract, with a minimum term of 15 years; and
- Modify the QF Proxy PPA standard offer contract to also apply to renewable energy RFPs, but with a 10% discount applied to the resulting proxy price in exchange for allowing the QFs to retain environmental attributes.

II. Application of fuel cost forecast in Georgia Power's calculation of the avoided cost of energy

Q: Please summarize your concern with Georgia Power's calculation of fuel costs for the avoided cost of energy as filed in direct testimony.

A: The Commission's current requirement is that Georgia Power's avoided cost of energy should include six components, including:

- System territorial spot fuel lambda
- Fuel cost multiplier
- Marginal cost multiplier
- Variable O&M component multiplier
- Emissions component adder
- Start-up & commitment component adder

Fuel costs affect the system territorial spot fuel lambda, fuel cost multiplier, and the start-up & commitment component adder.

In my direct testimony, I explained that the full cost of natural gas to Georgia Power's power plants includes both the cost of fuel, as represented by the Henry Hub spot market price, and additional commodity charges to transport the gas along trunk pipelines from Louisiana to locations near its plants, as well as charges to move the gas from the mainlines to the plants. Based on the evidence I had available at the time I filed that testimony,[1] it appeared that Georgia Power was not including variable transportation, storage costs or fuel retention costs in its planning forecast or day-ahead costs.

Q: What commodity charges does Georgia Power pay for natural gas?

A: In response to STF-6-8(d), Georgia Power stated that, in addition to the Henry Hub fuel price forecast, the Company's fuel cost assumptions include variable transportation and storage costs and fuel retention costs. Georgia Power asserted that the storage withdrawal costs (including related fuel retention costs) "are not included in the Company's fuel cost assumptions because gas storage capacity is fairly limited and mostly used for daily balancing." The Company also excludes what it represents as "fixed transportation and storage costs."

In response to STF-10-1, Georgia Power provided its forecast of these commodity charges. The description of the charges in the forecast is similar to that of the historical data, but also includes taxes.

The contract or tariff basis for these charges was not provided by Georgia Power. Data Request STF-8-4 specifically asked for contract structures including

[1] In data request STF-6-8(c), Georgia Power was asked to provide both historical and forecast data related to the procurement of natural gas. In its response, the Company provided a Trade Secret attachment with historical data related to these costs, but no "forecasts of the same." When asked to identify where in its response the Company provided forecast data, if available, Mr. Weathers asserted that, "Question 6-8 … is asking about historical data," and proceeded to discuss only the historical data that were provided, and did not identify any response to the question about forecast data. The Commission hearing on direct testimony would have been better informed had the Company provided a complete response to STF-6-8.

all conditions relevant to the price and quantity delivered. In its response, Georgia Power provided only one charge, the transport rate, expressed in MMBtu/month.

A. Fixed Transportation and Storage Costs

Q: Please summarize the evidence regarding fixed transportation and storage costs.

A: Georgia Power reports actual "fixed transportation and storage costs" on Tab 5 of TS STF-6-8 Attachment A, and transport rates for each gas-fueled power plant in the STF-8-4 Attachment.[2] However, the actual costs do not match the contract rate.

In fact, the historical "Fixed Transportation & Storage Costs" reported on Tab 5 of TS STF-6-8 do not appear to be fixed. The costs vary from month to month, and often cease for several months at a time. Georgia Power has not provided sufficient evidence in the form of contract terms (as requested in STF-8-4) or the nature of reported charges (as requested in STF-6-8) to prove that these charges are entirely fixed costs.

In Trade Secret Figure 1, I have graphed the actual "Fixed Transportation & Storage Costs" for Plant McDonough (as an example) provided in response to STF-6-8 in comparison to the "Transport Rate" provided in response to STF-8-4.

Figure 1: Plant McDonough Fixed Costs vs Contract Cost (Trade Secret)

REDACTED

Sources: Georgia Power, responses to TS STF-6-8, Attachment A and TS STF-8-4, Attachment.

Trade Secret Figure 1 demonstrates that actual costs reported for Plant McDonough **REDACTED** the amount indicated as the fixed contract rates with Southern Natural Gas (SNG) for pipeline transportation and Leaf River for storage in 2015-2019, and then **REDACTED** the fixed contract rates in 2019. Furthermore,

[2] Georgia Power did not provide a forecast of fixed transportation and storage costs because such costs should be irrelevant to the calculation of avoided costs.

the difference between the contract rates and actual costs varied over this timeframe, suggesting that a portion of the costs for these two contracts was variable and hence avoidable.

Trade Secret Figure 1 also demonstrates that although the Plant McDonough transportation and storage contract information provided by Georgia Power in response to STF-8-4 indicated only two companies, the actual transportation and storage costs reported by Georgia Power in its response to STF-6-8 included **REDACTED** companies. As indicated by the difference between the "SNG and Leaf River Only" line and the "All Pipeline/Storage Cos." Line, these additional charges varied significantly from month to month, suggesting that these costs were mostly or entirely variable and hence avoidable.

For these two reasons, I conclude that the "Fixed Transportation & Storage Costs" are not entirely fixed and that Georgia Power has not demonstrated that it is correctly distinguishing between fixed and variable costs.

Q: How should the Commission respond to the lack of evidence regarding the fixed transportation and storage costs?

A: I recommend that the Commission direct Georgia Power to take the following steps:

- Provide full details regarding all fixed transportation and storage costs reported in TS STF-6-8 Attachment A, Tab 5 sufficient to justify each cost, including the volumetric (per mmBtu), capacity (per contract mmBtu), or periodic (monthly) basis for each cost, and evidence linking the rates to specific contract terms; and
- A classification as to the variable, fixed, or mixed basis for each cost with a clear justification for the classification.

If either Georgia Power or the Commission determines that any of the costs are misclassified as fixed and should, in fact, be variable, then Georgia Power should be required to update its forecast of fixed transportation and storage costs and avoided energy costs accordingly.

B. Storage Withdrawal Costs

Q: Is it reasonable to exclude storage withdrawal costs from the avoided cost of energy?

A: Yes, but these costs are potentially avoidable. In its response to STF-6-8, Georgia Power states that storage withdrawal costs, as well as fuel retention and transportation and storage costs are "not included in the Company's fuel cost assumptions because gas storage capacity is fairly limited and mostly used for daily balancing." I verified that there is no clear relationship between volumes of storage withdrawal and volumes of fuel consumption, and generally agree that it is reasonable to exclude these costs from the avoided cost of energy.

Storage withdrawal costs could be avoided by a resource that reduced daily balancing, such as battery storage. Accordingly, I recommend that the Commission direct Georgia Power to develop an avoided storage withdrawal cost, potentially as a modification to the RCB Framework, which would be available to battery storage and other similar resources.

C. Variable transportation, storage, and fuel retention costs

Q: What variable costs does Georgia Power state are included in its fuel cost assumptions?

A: Georgia Power states in its response to STF-6-8 that in addition to the cost of fuel, other variable fuel costs include variable transportation and storage costs and fuel retention costs related to purchased fuel costs. In STF-10-1, Georgia Power provided similar variable costs used in its fuel cost forecast. The forecast data also include taxes.

Q: Has Georgia Power demonstrated that it is including those costs in its models?

A: Yes. In Georgia Power's response to STF-10-1, the Company provided a detailed, plant-specific fuel cost forecast including the basis differential, fuel retention, transportation, and taxes. Compared to the historical data provided in response to STF-6-8, Georgia Power's forecast is similar for most plants. In three cases the forecast costs were significantly **REDACTED**, and in one case significantly **REDACTED**.

Table 1: Variable Fuel-Related Costs Reported by Georgia Power, 2015-2020 vs Forecast Delivery Price, 2020 ($ / mmBtu)

Gas Plant	*Variable Fuel-Related Costs*	*Forecast Delivery Price*
Addison	**REDACTED**	**REDACTED**
Dahlberg	**REDACTED**	**REDACTED**
Harris	**REDACTED**	**REDACTED**
Heard County	**REDACTED**	**REDACTED**
McDonough CC	**REDACTED**	**REDACTED**
McIntosh	**REDACTED**	**REDACTED**
Monroe	**REDACTED**	**REDACTED**
Tiger Creek (Washington County)	**REDACTED**	**REDACTED**
Walton County	**REDACTED**	**REDACTED**
Wansley	**REDACTED**	**REDACTED**
Yates	**REDACTED**	**REDACTED**

Sources: Georgia Power responses TS STF-6-8, Attachment A, TS STF-10-1 Attachment. Excluding historical data for plants without forecast values. Excluding Plant McDonough CT due to likely error in data. Forecast delivery price is the average of monthly delivery prices.

Q: Does Georgia Power's forecast of variable fuel costs appear reasonable?

A: It appears reasonable, but I cannot determine it for certain. First, Georgia Power did not provide any evidence related to contract or tariff terms for variable costs for fuel retention, transportation and storage as requested in STF-8-4. Thus, it is not possible to determine if the forecast costs provided by Georgia Power are consistent with contract or tariff terms.

Second, as discussed above, there may be some costs that Georgia Power has miscategorized as fixed transportation and storage costs that should also be included in the forecast of variable fuel costs.

Q: How should the Commission respond to the incomplete evidence regarding variable costs?

A: The Commission should direct Georgia Power to update its response to STF 8-4 with contract terms for plant-specific fuel retention, transportation and storage costs.[3] The Commission should also direct Georgia Power to provide a plant-specific comparison of contract terms with historical and forecast data. As recommended above, additional transportation and storage costs identified as variable costs, should be included in this comparison. Georgia Power should be required to provide evidence that its fuel cost forecast is fully aligned with historical data and contract terms for fuel-related variable costs, and to provide updated avoided costs if the review determined that there is good reason to revise the forecast of variable costs.

III. <u>Continuation of the fuel cost multiplier in Georgia Power's calculation of the avoided cost of energy.</u>

Q: Should the fuel cost multiplier be removed from the PURPA avoided cost calculation?

A: No, the fuel cost multiplier is necessary to calculate full PURPA avoided costs. In my direct testimony, I explained that the Commission established the fuel cost multiplier because QFs allow Georgia Power to avoid a blend of spot, short-term and long-term fuel contracts. Georgia Power continues to use short-term and long-term (up to three year) coal contracts. Georgia Power may also be using other types of financial instruments to manage the cost of natural gas without considering the costs of those instruments in its fuel costs.

Furthermore, Georgia Power assumes that the fuel cost multiplier will be zero beyond the first three year period.

[3] Some of this information is implied in the response to STF-10-1, but there are no sources cited for the indicated values.

Q: Why is it important to fully consider all fuel contract costs?

A: Fuel contract costs are avoidable costs. For both coal and natural gas, Georgia Power uses contracts and financial instruments to reduce its cost of fuel as well as to reduce fuel price volatility. These contracts and financial instruments have costs, and those costs are generally volumetric. Thus, they increase (or, occasionally, decrease) the unit cost of fuel procurement. Energy supplied by QFs can reduce these additional costs.

It is also important to consider these costs beyond the first three years. The avoided costs generated for PURPA purposes are used in certain long-term forecasts, such as in DSM cost-effectiveness analysis and in the analysis or setting of fixed price contracts for renewable energy resources. Even though Georgia Power may only enter into such contracts for the next several years, Georgia Power is likely to continue entering into such contracts for the full ten years included in its avoided cost forecast. The incremental costs associated with such contracts are avoidable.

Q: What has the fuel cost multiplier been in previous years?

A: Georgia Power files annual updates to the fuel cost multiplier. In the filings I reviewed, the fuel cost multiplier has varied from 1.02 to 1.23. However, Georgia Power's current multiplier is close to or at 1.0 for 2022-2030.[4] A complete history of the fuel cost multiplier has been requested in STF-11-2.

Q: What do you recommend?

A: I have three recommendations. First, I recommend that the Commission direct Georgia Power to continue to utilize the fuel cost multiplier in its forecast,

[4] The value for 2022 is provided in a Trade Secret filing only, after 2022 the multiplier is not used. Georgia Power, Response to STF-4-1(a).

consistent with the 1994 Order,[5] denying the Company's request to eliminate it. The multiplier should be updated to reflect all financial instruments that the Company is using to manage fuel contract costs.

Second, I recommend that the Commission revise the method to also apply the fuel cost multiplier to startup and commitment costs. Georgia Power's witness panel indicated that startup and commitment costs primarily consist of production costs, which include a fuel cost component. It would be appropriate to apply the fuel cost multiplier to fuel costs embedded in the startup and commitment costs. If it is not possible to distinguish fuel costs from other startup and commitment costs, then it would be reasonable to apply the fuel cost multiplier to all such costs, since fuel costs are likely to be the vast majority of startup and commitment costs.

Third, the Commission should direct Georgia Power to include a fuel cost multiplier in all forecasts of avoided energy costs, particularly where the future years of that forecast have a meaningful impact on either a policy decision (e.g., DSM cost-effectiveness) or on a fixed-price contract (e.g., application of the RCB in bid evaluation). Since Georgia Power's contracts and financial instruments are primarily targeted at the next few years, Georgia Power should use an average of prior-year fuel cost multipliers as a minimum floor.

IV. <u>Application of marginal cost multiplier in Georgia Power's calculation of the avoided cost of energy.</u>

Q: Should the marginal cost multiplier be removed from the PURPA avoided cost calculation?

A: No. As I explained in my direct testimony, in 1994 the Commission established a marginal cost multiplier because the "territorial system lambda systematically

[5] Georgia Public Service Commission, Order in *Capacity and Energy Payments to Cogenerators Under PURPA*, Docket No. 4822-U, October 11, 1994. ("1994 Order")

underestimates the full costs avoided by the introduction of a QF."[6] The Commission relied on the testimony of Staff Witness Mr. Davie, who explained that without the multiplier, the actual energy costs avoided would be understated "because QFs, in aggregate, allow the utility to avoid a larger block of power than is typically measured by the system lambda."[7]

In its direct testimony, Georgia Power's witness panel asserted that "the QF program does not meaningfully change system dispatch, or, therefore, influence the Company's marginal costs."[8] This seems absurd.

Georgia Power currently includes 32 QFs in its monthly report, including 10 QFs that receive monthly capacity payments and 3 additional QFs that are eligible for capacity payments.[9] In Georgia Power's October 2020 QF report, filed in Docket 1, the Company reported 186 million kWh of generation by all qualified facilities. This represents average hourly generation of about 250 MWh, sometimes more and sometimes less.

In my opinion, 266 MWh is sufficient to meaningfully change system dispatch.

Q: Did Georgia Power's panel offer any other reasons to remove the marginal cost multiplier?

A: Yes. The panel asserted on several occasions that the "unit commitment cost [adder] is capturing the impact that the marginal cost multiplier was intended to capture."[10]

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[6] 1994 Order, p. 14.

[7] Georgia Public Service Commission Staff IRP Adversary Team, *Direct Testimony of Douglas E. Davie*, Docket No. 4822-U (May 27, 1994), p. 36. ("1994 Davie Testimony")

[8] Georgia Power, direct testimony, p. 43, lines 14-16.

[9] Georgia Power, response to STF-6-5 and Georgia Power, *Co-Generator/SPP Purchases for October 2020*, Docket No. 1 (November 19, 2020).

[10] Transcript, p. 209, lines 10-12.

Q: Is there any merit to Georgia Power's claim that the unit commitment cost adder captures the effect that the marginal cost multiplier was intended to capture?

A: No, Georgia Power's witness panel has confused two distinct concepts.

The unit commitment cost adder is intended to capture the effect of an individual QF project being compensated under a PURPA PPA on the unit commitment costs for the system. This is demonstrated by the fact that its units are dollars per megawatt-hour ($/MWh), so the unit commitment benefits are scaled proportionate to the energy delivered by the QF.

In contrast, the marginal cost multiplier is unitless – it is a multiplier. It is intended to adjust the overall marginal costs to reflect the impact of "QFs, in aggregate" on the system lambda, as noted above, quoting Mr. Davie.

In summary, the adder is the effect of an individual QF unit, the multiplier is the effect of already existing QFs, in aggregate. The Georgia Power witness panel incorrectly conflates two different effects.

Q: Is it significant that Georgia Power's current methodology for calculating the marginal cost multiplier may be out of compliance with the 1994 Order?

A: It appears likely to be very significant. In the 1994 Order, the Commission noted that Mr. Davie estimated the marginal cost multiplier to be "at around 1.02."[11] A 2 % increase in the avoided cost of energy could be significant to a QF.

Q: Has Georgia Power provided any evidence that demonstrates the potential value of the marginal cost multiplier?

A: Yes. In response to STF-10-4, Georgia Power provided base and sensitivity cases for +/- 1000 MW and +/- 2000 MW.

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[11] 1994 Order, p. 12.

Because the capacity factor of the QFs is not known, I assumed a 50% capacity factor for October 2020. Based on the average hourly generation of 266 MWh discussed above, the QFs might have a capacity of 532 MW.

In order to calculate the marginal cost multiplier, I used the average change in the system lambda per megawatt of additional capacity, comparing the +/- 1000 MW sensitivities to the base case.

Using this approximation, I found that the marginal cost multiplier is not much changed from the value Mr. Davie recommended in 1994. My calculations are shown in Trade Secret Exhibit JDW-5.

Q: Is there a better way to calculate the marginal cost multiplier?

A: Yes. Ideally, Georgia Power would provide the provide the avoided cost of energy resulting from two production cost model simulations, one with the QF resources, and one without the QF resources, as required by the 1994 Order in Docket No. 4822. In response to Staff Data Request STF-8-1, Georgia Power did not provide the analysis required by the 1994 Order. The Company asserted in its response that "The calculation of unit commitment/startup costs includes the production cost impacts that would result from the two production cost model simulations described in the Commission's 1994 Final Order. Therefore, to prevent double counting, no separate production cost model simulations with and without Qualifying Facility ("QF") resources are needed."[12]

As discussed above, Georgia Power has confused two distinct concepts in this response. The Commission should direct Georgia Power to provide the requested response, which would provide a more definitive estimate than the value I suggested above.

[12] Georgia Power, response to STF-8-1(a).

Q: What do you recommend?

A: The Commission should continue use of the marginal cost multiplier, denying the Company's request to eliminate it. I restate my recommendation in my direct testimony: The Commission should direct Georgia Power to demonstrate that its marginal cost multiplier assumption of 1.0 is consistent with method and intent of the 1994 Order, or to provide a calculation consistent with the 1994 Order for review by other parties.

In order to expedite a decision in this proceeding, the Commission could simply direct Georgia Power to use a marginal cost multiplier of 1.02 unless it presents compelling evidence as to another appropriate value. In my opinion, that value would be reasonable and could be updated by Georgia Power in its 2021 filing.

In addition, consistent with my recommendation regarding the fuel cost multiplier, I also recommend that the Commission revise the method to also apply the marginal cost multiplier to startup and commitment costs. My reasoning is the same as above – since the marginal cost multiplier is intended to adjust the system lambda, to the extent that the commitment cost adder relies on the system lambda, then it too should be adjusted to reflect the full impact of existing QFs on system costs.

V. Application of capacity need forecast in Georgia Power's projection of avoided capacity cost.

Q: Please restate your recommendations for determining the avoided capacity cost in each year in which there is not a resource need.

A: In my direct testimony, I recommended that the Commission direct Georgia Power to calculate its avoided capacity cost based on its forecast reserve margin. For a given reserve margin value, the avoided capacity cost should be set at the value where it would be economic for customers if the system carried that additional amount of reserves.

I also recommended that Georgia Power conduct the necessary studies to determine the avoided cost of capacity associated with the retirement of Plant Wansley units 1 and 2 and use that avoided capacity cost if it is greater than the amount determined by the reserve margin study method. The same would be true of any other resources that could be economically retired, were additional capacity available.

Q: Did the Georgia Power witness panel agree with the economic principles you described in your direct testimony?

A: Yes. During cross-examination by Mr. Carver, the witness panel generally agreed with the economic principles I described in my direct testimony. For example, Mr. Grubb agreed that it would be within the jurisdiction of the Commission to set the avoided cost of capacity above zero under certain conditions.[13] Furthermore, Mr. Weathers stated, "Generally, if the cost of capacity is cheaper on an economic basis then it will be more economic for customers to carry a larger number of reserves."[14]

Mr. Weathers' statement affirms the fundamental justification for my recommendations. It is appropriate for the PURPA avoided cost rate to include capacity payments that result in a larger reserve capacity.

I do acknowledge that Georgia Power did not agree with my recommendation, and that the witness panel maintained that the Commission should continue to limit avoided capacity payments to years in which there is a demonstrated cost of needed capacity that can be avoided. In my opinion, the

[13] Transcript, p. 224, line 24 – p. 225, line 1.

[14] Transcript, p. 222, line 25 – p. 223, line 3.

Company's position is not in the fundamental economic interest of its customers as it delays discount capacity purchases until the forecast year of need, when it then makes those purchases at full cost, thus foregoing benefits that could be available due to earlier purchases.

Q: So are you saying that Georgia Power's proposed avoided costs would bypass potential "discount offers" from QFs?

A: Yes, by augmenting the avoided capacity cost rate with payments in advance of the next year that capacity is needed, the Company may be able to contract for capacity at a price that is lower than it would otherwise pay for a CT generation unit.

In personal terms, this is like passing up a sale price at the grocery store because you don't need the food until next week. Buying the food (or QF power) in advance means that the customer (or utility) has the opportunity to use that food should an unexpected need develop, which represents a value to the customer while also generating long term savings because of the discount price.

Q: Would your proposal be a drastic departure from current and longstanding practices of the Commission?

A: No. My recommendation is entirely consistent with the practices for setting the target reserve margin and determining the value of avoided capacity. I am recommending a policy change, and suggest that the Commission apply those practices to some circumstances that the Commission has previously not considered.

My recommendation is also consistent with the Commission's existing "extraordinary advantage" policy, as Commissioner Echols pointed out during the direct testimony hearing.[15] As I testified in the 2019 Integrated Resource Plan proceeding, Georgia law includes a particularly useful provision known as the

[15] Transcript, p. 725, line 18 – p. 726, line 8.

"extraordinary advantage" standard, which the Commission most recently applied to authorize Georgia Power to acquire low-cost wind power resources.[16] By setting an above-zero (but still discounted) avoided cost of capacity for pre-need years, the Commission would simply be applying the principle of extraordinary advantage to PURPA QF rates.

In fact, this proceeding gives the Commission the opportunity to quantify the extraordinary advantage rule. By ruling that the value of above-reserve-margin capacity is determined by estimating the optimal economic carrying cost at the projected reserve margin in non-need years, the Commission will have an explicit basis on which to consider any future extraordinary advantage contract opportunities proposed by Georgia Power.

Furthermore, Georgia Power is known for not simply meeting baseline reliability standards, such as NERC and storm recovery standards, but striving to exceed them. By adjusting the avoided cost of capacity to compensate QFs at a "discount" rate for capacity above and beyond the target reserve margin, I am suggesting that Georgia Power apply these same values to resource acquisition, and to acquire additional resources in advance of the need when they are available at an appropriate "discount" price.

Q: Why shouldn't Georgia Power simply procure "discount" resources through the extraordinary advantage rule?

A: Because it isn't simple to use that rule. Any contract that Georgia Power proposes under the extraordinary advantage rule must go through a full Commission certification proceeding. In contrast, standard offer contracts are considered "pre-approved" and require a much less costly and time-consuming approval process.

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[16] Commission Rule 515-3-4-.04(3)(f)(3). See Docket No. 37854, Georgia Power Company's Application for Certification of the Power Purchase Agreement for Wind Resources from the Blue Canyon II and Blue Canyon VI Wind Farms.

From the perspective of a small QF, there would be a strong preference for a simple process, not a more complicated one.

Q: Is intentionally over-procuring capacity consistent with the concept of avoided cost?

A: No. Capacity itself has no value to customers, it is the reliability provided by having a certain amount of capacity that is what customers value. This is verified directly in Georgia Power's method for balancing the economic carrying cost of a combustion turbine with the value to customers of providing reliability to customers.

The concept of over-procuring capacity is a red herring. It is entirely possible for a utility to over-invest in reliability by spending too much on generation resources or, for that matter, overbuilding transmission and distribution systems. The focus should be on the price and overall level of investment, not on a specific capacity need target determined based on pricing assumptions that may not hold for some QFs.

Q: Are you advocating that Georgia Power's avoided cost rates include payment for additional reliability benefits from excess capacity above the target reserve margin?

A: Yes. As I stated in my direct testimony, customers benefit from (a) reduced reliability-related costs, (b) reduced fuel costs due to income that Georgia Power may earn by selling excess capacity on the bilateral market, particularly during periods of regional demand shortages, and (c) retirement of excess capacity and avoidance of associated fixed operating and maintenance costs.

Focusing on reliability, rather than capacity, is consistent with Georgia Power's advocacy of the additional cost and benefit considerations in the RCB Framework, which it suggests applying to PURPA avoided costs in this proceeding.

For example, Support Capacity, in the RCB Framework, "represents the impact that renewable resources have on the reliability of the System."[17] Thus, QFs whose operation requires additional support capacity receive lower compensation due to the additional reliability costs as measured using the RCB Framework. This reliability transaction should go both ways: QFs that offer additional reliability to the system should be compensated for that value.

VI. <u>Georgia Power's calculation of the cost of new capacity.</u>

Q: Please summarize your recommendations for calculating the cost of new capacity.

A: In my direct testimony, I recommended that the Commission direct Georgia Power to use a transparent, publicly-available Southeast-specific value from the US Energy Information Administration (EIA) for the ECC of a CT when setting avoided capacity cost.

Q: What if the reason that Georgia Power's cost forecast is lower than the EIA Southeast cost forecast is due to economies of scale or other specific cost advantages that Georgia Power is considering?

A: The Commission should consider those cost advantages specifically, but in general, many of those cost advantages may represent opportunity costs. For example, if Georgia Power's cost estimate assumes a brownfield site – a site with existing underutilized transmission resources – then the use of those resources represents an opportunity cost. So that cost advantage is not truly cost-free.

Similarly, an economy of scale represents a cost advantage of procuring a large amount of capacity at a single time. Assuming that cost advantage presumes that the Commission will approve such a large capacity purchase.

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[17] RCB Framework, revised January 17, 2019, p. 24.

The Company's cost estimate may also be lower because it believes that it can achieve cost savings due to better-than-average procurement or risk management practices. As Commissioner Echols discussed during the direct testimony hearing, Georgia Power has had cost overruns with generation projects in the past.[18] While I would certainly like to believe that the Company will be able to achieve better-than average costs in the future, it should not be assumed for cost forecasting purposes in this proceeding.

Nonetheless, I would not categorically rule out the application of cost advantages in setting an avoided cost of capacity. I recommend that the Commission require Georgia Power to begin with the publicly-available, transparent and region-specific cost forecast from EIA, and then authorize Georgia Power to make specific adjustments to the EIA number that are well-justified and do not represent opportunity costs or rosy assumptions about cost control or risk management.

Q: Are there any other reasons that Georgia Power might be underestimating the cost of new CT capacity?

A: Yes. In my experience, some utilities are grappling with a need to acquire additional gas-fueled resources, while also being aware that their Commission or government policy will result in those resources having a shorter lifetime than has usually been considered to be the case. A shorter lifetime may mean that the utility needs to use accelerated depreciation to recover costs, and to reflect fewer years of system benefit from that capacity investment.

Considering that today's CT capacity investment may be useful for only twenty years or so, the carrying cost of that CT capacity will be higher than if the investment is considered to be useful for thirty or forty years.

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[18] Transcript, p. 733, line 21 – p. 734, line 9.

The Commission may wish to request that Georgia Power study the impact of a shorter lifetime for gas-fueled generation units on capacity cost in the next integrated resource planning proceeding. Depending on the Commission's response to that study, it may be appropriate to assume a shorter lifetime for CT capacity in future avoided cost proceedings.

Georgia Power's Standard Offer Contract Options.

Q: Do Georgia Power's proposed Standard Offer Contract Options allow for adequate and appropriate compensation of capacity provided by PURPA QFs?

A: No. Georgia Power's proposed Standard Offer Contract Options are not structured to allow for adequate and appropriate compensation to intermittent or energy-limited resources, such as solar, wind and battery storage for capacity benefits delivered to Georgia Power.

- **The QF Proxy PPA** requires a QF to "either bid into a capacity-based RFP or submit an NOI to supply some of the capacity need," and must meet standards defined in the RFP.[19] Since Georgia Power's capacity-based RFPs have standards that make most intermittent or energy-limited resources ineligible,[20] the QF Proxy PPA is unavailable to most of those resources.
- **The QF Energy-Only PPA** is only offered to a QF desiring to sell energy, and only energy, to Georgia Power. The QF has no obligation to deliver energy to Georgia Power.

[19] Georgia Power, direct testimony, p. 23, lines 19-21.

[20] GLSSA Business Panel, direct testimony, p. 28, lines 3-19.

- **The QF Capacity and Energy PPA** is offered to QFs desiring to sell capacity and energy to Georgia Power. The QF must deliver firm capacity[21] demonstrate a Peak Period Hours Capacity Factor of 60%.[22]

Thus, unless the QF is eligible to participate in a capacity-based RFP, or is able to deliver firm capacity and demonstrate a Peak Period Hours Capacity Factor of 60% during every annual period, then intermittent or energy-limited resources are excluded from compensation for avoided capacity benefits.

Intermittent or energy-limited resources should be eligible for avoided capacity benefits. Using the RCB Framework, the Commission has approved numerous PPAs whose compensation is the result of a competitive bidding process as well as being capped by avoided costs – including avoided capacity costs. Thus, the Commission has established ample precedent that solar and other renewable resources deliver capacity benefits to the Georgia Power system, as valued in the RCB Framework.[23]

Q: Do Georgia Power's proposed Standard Offer Contract Options allow for adequate and appropriate compensation of energy provided by PURPA QFs?

A: Yes. Subject to the recommendations for the correction or revision of specific elements of the calculation of the avoided cost of energy, the QF Energy-Only PPA and the Firm Energy and Capacity PPA are structured to provide adequate and appropriate compensation for the energy delivered to the Georgia Power system by intermittent or energy-limited resources. As discussed below, the QF Proxy PPA could also be structured to achieve the same outcome.

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[21] Firm capacity is not defined in the PPA, except by reference to Committed Capacity. Committed Capacity must be demonstrated by a Performance Test to be drafted by the Parties to the PPA.

[22] Exhibit JRG/AWM/JBW-4, Section 13.1.10, p. 19.

[23] If solar and other renewable resources did not deliver capacity benefits to the Georgia Power system, then bid evaluations in renewable energy RFPs would be capped at the avoided cost of energy and exclude capacity and capacity-related benefits and costs.

Q: Why does Georgia Power object to paying QFs for capacity and capacity-related benefits?

A: Georgia Power's position is that that payments to QFs for capacity, and capacity-related benefits, are not appropriate because contracts for QFs may be terminated with only 365 days' notice.[24] Georgia Power's witness panel testified that QFs under Docket No. 4822 have "no true long-term commitment to the Georgia Power system, [and thus] it is not appropriate to value any capacity related benefits or costs created, as they cannot be relied upon in the Company's long-term planning."[25] Georgia Power has not taken a clear position as to why the QF Proxy PPA should be limited to capacity-based RFPs.

Q: What is your response to Georgia Power's position?

A: Georgia Power's position is based entirely on the terms of its own PPAs. As discussed above, it is the terms of Georgia Power's proposed standard offer contracts that make it impossible for QF's to make a "true long-term commitment."

Q: How do you recommend that QFs receive adequate and appropriate compensation for capacity benefits delivered to the Georgia Power system?

A: I recommend that the Commission approve a QF Rated Capacity and Energy PPA standard offer contract that would enable QF's to make a "true long-term commitment," and modify the QF Proxy PPA to enable QFs to participate in Georgia Power RFPs such as the Renewable Energy Development Initiative (REDI), the Customer Renewable Subscription Program (CRSP), or any other RFP for which a QF would be eligible but for its size.

[24] Georgia Power, direct testimony, p. 46, lines 22-25.

[25] Georgia Power, direct testimony, p. 59, line 18 – p. 60, line 3.

A. Proposed QF Rated Capacity and Energy PPA Standard Offer Contract

Q: Please describe your proposed QF Rated Capacity and Energy PPA standard offer contract.

A: I have attached a red line version of a proposed contract as Exhibit JDW-4. I further recommend that the Commission set the minimum term for this standard offer contract at 15 years in order to ensure the QF represents a long-term commitment to the Georgia Power system, direct Georgia Power to consider longer contract terms, and direct Georgia Power to provide a confidential, non-binding 20-year forecast of energy and capacity payments to QFs on request.

The proposed QF Rated Capacity and Energy PPA standard offer contract is a modified version of Georgia Power's proposed QF Firm Capacity and Energy PPA (Georgia Power Exhibit JRG/AWM/JBW-4). The proposed language includes no significant changes with respect to the structure of compensation using the avoided cost of energy. I have modified it to achieve the following objectives:

- Capacity payments to be based on Rated Capacity, as determined by the RCB Framework using the Incremental Capacity Equivalent Method or its successor;
- Energy payments to be based on the Avoided Cost of Energy, with full consideration of all RCB Framework costs and benefits, except that sum of the Capacity payment and the capacity-related RCB Framework elements cannot be less than zero;
- Annual update of Rated Capacity, as discussed below;
- Capacity payments to be returned in the event of early termination (as noted above, the minimum term should be set at fifteen years); and
- All energy output from the QF must be delivered to Georgia Power, with the exception of approved emergency service to a Georgia Power customer.

These modifications provide intermittent or energy-limited QFs with a reasonable option for obtaining payment for capacity benefits to Georgia Power, while respecting the concern expressed by the Georgia Power witness panel that capacity benefits should be paid only to facilities that are obligated to provide a long-term guarantee for delivery of such capacity benefits.

Consistent with Georgia Power's perspective, not only should QFs be paid for Rated Capacity, but also for capacity-related benefits (and costs) as defined in the RCB Framework.

I would like to emphasize that the proposed standard offer contract language in Exhibit JDW-4 is only intended to illustrate the four changes listed above. It may be necessary to make other modifications to this and other standard offer contracts to fully implement other recommendations in my testimony, or the recommendations of other witnesses.

Q: Please explain how you suggest that Georgia Power should update the Rated Capacity annually.

A: Georgia Power should update the Rated Capacity on an annual basis in order to account for the changing value of QF capacity to the Georgia Power system. In the 1994 Order, the Commission stated that, "There are ratepayer risks associated with fixed [energy] payments based on projections."[26] The approach I propose honors that decision.

There are two aspects to the Monthly Capacity Payment in the proposed PPA: Rated Capacity and the Annual Capacity Rate. The Rated Capacity reflects the marginal capacity benefit that the QF provides to the system. This marginal capacity benefit depends on what other resources are present on the Georgia Power system at that time.

[26] 1994 Order, p. 18.

For example, it is well established that as additional solar power is added to the Georgia Power system, the capacity benefit of the marginal solar unit will diminish. On the other hand, for QFs that include storage capabilities, updates to software, operating practices or, if allowed by Georgia Power, hardware could enhance the capacity benefit of the facility. For this and perhaps other reasons, the marginal capacity benefit that the QF provides to the system may change over time.

Thus, I recommend that the Rated Capacity should be re-evaluated by Georgia Power on an annual basis consistent with the RCB Framework or its successor and the most current assumptions appropriate to application of the RCB Framework. The Incremental Capacity Equivalent for each QF should be based on the marginal benefit of the QF, or of a generic facility that is substantially similar to the QF, considering all resources committed to the existing Georgia Power system at the time of the annual re-evaluation.

With respect to the Annual Capacity Rate, the compensation rate should be fixed at the time of contract approval, consistent with the current QF Firm Capacity and Energy PPA. This is appropriate because otherwise, the QF will never be able to obtain a full capacity payment associated with an avoided unit since such units are specified in advance.

Q: Please explain how you would treat the RCB Framework costs and benefits in this proposed PPA.

A: Georgia Power proposes to have the RCB Framework apply to QFs, except in the case of the QF Energy-Only PPA, where it would not apply capacity-related costs and benefits. Applying the RCB Framework to the QF Rated Capacity and Energy PPA could result in a negative value, even after consideration of the Capacity payment.

If the combination of the Capacity payment and the capacity-related costs and benefits (hereafter, "total capacity-related payment") is negative, then the QF would receive a lower payment than if it simply accepted the QF Energy-Only PPA. However, since the QF is not in a position to know whether the total capacity-related payment might become negative in the future, this possibility would make it difficult or impossible from a business perspective to sign this QF contract. A negative total capacity-related payment would put the QF in a position of having to pay for the opportunity to sell energy to Georgia Power at the avoided cost of energy.

To avoid this unreasonable outcome, I recommend that the total capacity-related payment have a floor of zero, so that it cannot be negative.

Energy-related components of the RCB Framework would continue to be applied.

Q: Why do you recommend that Georgia Power be directed to provide a 20-year forecast of energy and capacity payments to QFs?

A: The proposed QF Rated Capacity and Energy PPA will offer variable energy and capacity payments to QFs, depending on future conditions. Because the payment amounts are not provided in the standard offer contract, it will be difficult for a financing entity to develop confidence in a forecast of potential payments provided by the QF. Georgia Power is in a unique position to provide an authoritative forecast of a 20-year payment stream.

The forecast should remain confidential between Georgia Power, the QF, and necessary business partners of the QF. The basis for the calculations need not be made available to the QF.

B. Modifications to QF Proxy PPA Standard Offer Contract

Q: Please summarize key provisions of the existing QF Proxy PPA standard offer contract.

A: Georgia Power's existing QF Proxy PPA provides developers an opportunity to participate in a capacity-based RFP and leverages existing PURPA provisions.[27] QFs may either submit a competitive bid, or submit a Notice of Intent (NOI) to supply capacity.

The NOI is available to all QFs up to 30 MWs, and it is my understanding that Georgia Power has routinely granted size requirement waivers to QFs larger than 30 MW allowing them to participate via the NOI process.

After the bid evaluation is complete, QFs that submitted an NOI then have the option to enter into a contract whose pricing reflects the same value as the last winning bid of the RFP, or the first bid displaced. The QF has options regarding the payment structure over a range of capacity or energy payments.

Q: Please summarize your proposed modifications to the QF Proxy PPA standard offer contract.

A: At the time that the next renewable energy RFP is initiated, the Commission should direct Georgia Power to also propose a QF Proxy PPA aligned with the terms of the RFP. However, instead of pricing at the same rate as the last winning bid of the RFP, I propose that the pricing offered to QFs be a 10% discount relative to the last winning bid, in exchange for allowing the QF to retain all environmental attributes as is the practice for PURPA standard offer contracts.

More specifically, by "last winning bid," I mean that the PPA price should be set at 10% less than the lowest pre-transmission imputed price of the winning bids as the QF would be required to bear all interconnection agreement costs. It is

[27] Georgia Power, direct testimony, p. 23, line 5 – p. 25, line 4.

possible that the lowest valued bid might not have the lowest pre-transmission imputed price since the bid value ranking relies on pricing plus transmission costs.[28]

I also recommend that the Commission allow all QFs, up to the PURPA limit of 80 MW, to participate using the NOI process in order to avoid the need to use waivers.

This approach would provide an opportunity for Georgia Power to acquire solar at an even lower price than it captured in a competitively bid renewable solicitation. Since all successful renewable energy RFP bids are, by definition, priced below avoided cost, as adjusted by the RCB Framework, then any QFs that sign a QF Proxy PPA would be providing power at a substantial (10%) discount to Georgia Power's forecast of avoided costs.

It is not certain that the solar industry can currently meet the price point necessary to deliver this value to the Georgia marketplace. This QF Proxy PPA would, however, create a mechanism of the Commission to strike on solar projects in the future that are able to deliver exceptional value.

Thus, I recommend that the Commission direct Georgia Power to propose a QF Proxy PPA aligned with all future RFPs for utility-scale resources, and to accept PPA requests on similar terms to the existing practices for the QF Proxy PPA offered in parallel to capacity RFPs. The PPA price should be set at 10% less than the pre-transmission imputed price of winning bids, and the PPA should not convey environmental attributes to the Company.

[28] The valuation process I suggest is similar to the existing QF Proxy PPA determination, in which "the incremental value produced by the QF is used to solve for a capacity price such that total evaluated cost, based on the QF's projected operational profile, is equal to that of the last bid selected or the first bid displaced …". Georgia Power, direct testimony, p. 23, lines 25-28.

C. Additional Considerations for Standard Offer Contracts

Q: Why do you believe that both options need to be added?

A: Georgia Power's customers will benefit whenever a QF is able to provide power at a lower cost than the existing or anticipated resources available to the Company. A key factor in providing lower costs is the cost of financing. Providing both options increases the likelihood that QFs will be able to identify low-cost financing and additional value (such as RECs) to provide "discount" resources to the Company's system, to the benefit of its customers.

The proposed QF Rated Capacity and Energy PPA is a simple option that would be available at any time to a QF that is willing to take the avoided cost rate on the basis of delivering 100% of energy generated on a must-take basis to Georgia Power.

In contrast, the QF Proxy PPA would only be available when an RFP is issued in which renewable energy QFs meet the performance standards of the RFP. QFs would be able to choose a must-take delivery option, or they could offer dispatch capability to Georgia Power. The GLSSA Business Panel's direct testimony discussed the development of flexible, dispatchable solar which would offer additional capabilities to Georgia Power.

Q: How should QF Rated Capacity and Energy PPAs and QF Proxy PPAs be considered in long-term planning?

A: Georgia Power should include the rated capacity for these QFs in long-term planning. Georgia Power's witness panel argued that including energy-only QFs in long-term planning is that the Company "would be basing reliability on contracts and resources that have no obligation to be here long term."[29] The long-term

[29] Transcript, p. 359, lines 5-8.

commitments proposed in both of these QF standard offer contracts would eliminate that concern.

Q: Does this conclude your testimony?

A: Yes.