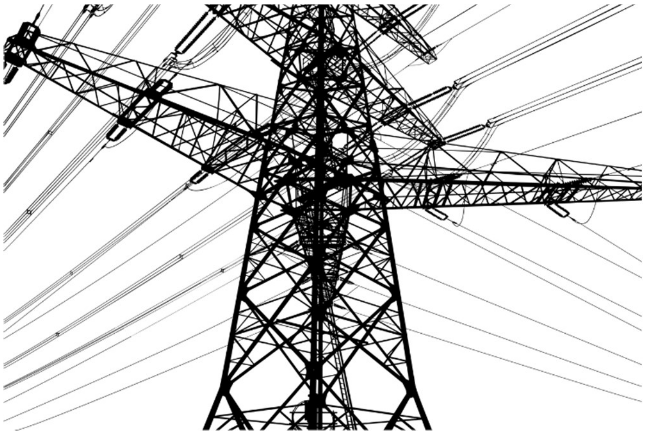

Utility Avoided Cost – A Tool for Valuing Renewable Energy and Utility Energy Efficiency Programs in Georgia

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(updated November 2021)

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Introduction

This primer aims to present an overview of the concept of utility avoided cost, particularly as that concept arises in utility compliance with the Public Utility Regulatory Policies Act of 1978 (PURPA), and how utility avoided cost impacts the value of renewable energy and energy efficiency in Georgia.

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What Is PURPA and Utility Avoided Cost?

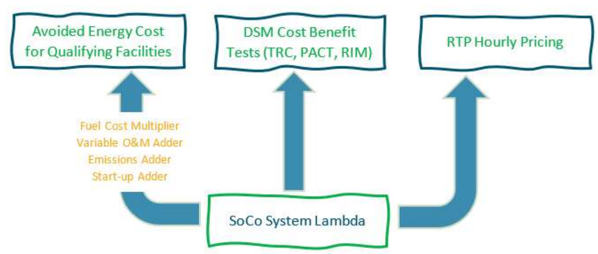
The Public Utility Regulatory Policies Act of 1978 (PURPA) promotes energy conservation and greater use of domestic and renewable energy resources. The Act also expanded competition in the electric power sector, which was, at the time, dominated by vertically integrated utilities. A key element of the Act was the definition of "Qualifying Facilities" (QFs) - small renewable energy or cogeneration facilities - and the associated requirements that utilities allow QFs to interconnect with the grid and that they buy the QF's energy and capacity at the utility's avoided cost. PURPA defines avoided cost as:

> Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6)

Why Does Avoided Cost Matter?

Utilities, like Georgia Power, use their calculation of hourly utility avoided cost to determine how much energy efficiency programming is cost-effective and to calculate how much they pay customers with distributed solar energy systems when they sell their excess electricity back to the grid. Higher utility avoided cost translates into higher levels of cost-effective energy efficiency programming and better compensation for cogenerators and solar energy facilities.

FIGURE 1. SYSTEM LAMBDA AS UNDERLYING CALCULATION



How Does It Matter to Different Segments of the Solar Industry?

While a higher utility avoided cost generally improves conditions for solar facilities in Georgia, it does not affect all segments of the industry equally. Table 1 below characterizes some of these differences.

Table 1. Solar facility contacting arrangements and related avoided cost impacts

Market Segment	Impacts
Qualifying facilities / facilities operating under standard offer agreements	Higher avoided cost will increase compensation for this market segment.
Customer-sited program participants	Higher avoided cost will increase compensation for this market segment.
RNR tariff subscribers (BTM solar)	Higher avoided cost will increase compensation for this market segment.
ASI / REDI utility-scale participants	Given program competitive bidding requirements, higher avoided cost will increase the number of projects able to participate in the program. It will not increase compensation for specific participants.
ASI / REDI DG participants	Same as above
CRSP participants	To be determined

How Utility Avoided Cost Impacts the Value of Utility Energy Efficiency Programs

In the early 1980s, the California Public Utility Commission developed the California Standard Practice Manual. Updated over the last 20 years, the manual lays out a standard approach to evaluating the cost effectiveness of utility-sponsored energy efficiency programs (a.k.a. "demand-side management" or DSM programs). The manual details five key cost-effectiveness tests that have been used by programs across the county for more than 30 years.

These five cost-effectiveness tests are:

- the Total Resource Cost (TRC) Test,
- the Ratepayer Impact Measure (RIM) Test,
- the Utility/Program Administrator Cost Test (PACT),
- the Participant Cost Test (PCT), and
- the Societal Cost Test (SCT).

Utility avoided energy and capacity costs is an essential input into the DSM cost tests. In fact, utility avoided cost is the exclusive benefit considered in the PACT and RIM tests and the predominant benefit considered in the TRC and SCT tests. Only the Participant Cost Test does not rely on utility avoided cost as an input.

Table 2. Utility Avoided Cost in DSM Tests

	Utility Avoided Costs Included as a Benefit
Total Resource Cost Test	✓
Ratepayer Impact Measure Test	✓
Program Administrator Cost Test	✓
Participant Cost Test	
Societal Cost Test	✓

History of Avoided Cost Regulatory Proceedings in Georgia

Georgia PSC Docket 4822

In 1994, the Georgia Public Service Commission opened Docket 4822 to examine capacity and energy payments to "cogenerators" under PURPA. The Commission issued its final order in October of that year. Since that time, Georgia Power has filed annual avoided cost projections in this docket, largely without controversy or comment. Further litigation in Docket 4822 opened in 2004 in response to Biomass Gas & Electric's petition for a power purchase agreement. Since that time, the Commission has not conducted any further examination of avoided cost methodology in Docket 4822.

Georgia PSC Docket 16573

In 2003, the Commission opened Docket 16573 to review Georgia Power's proposed Green Energy Program. Under this docket, the PSC approved certain solar-specific adjustments to Georgia Power's avoided cost calculations. This adjustment to the utility's avoided cost projections first appears in the 2013 avoided cost projections filing.

Georgia PSC Docket 19279 (and 4822) – BGE RE Plant

In July 2004, Biomass Gas & Electric (BG&E) filed a petition to establish a docket regarding its proposed Forsyth County Renewable Energy Plant. The docket unfolded in three phases, described below:

Phase 1 – Initial Challenge

- July 20, 2004 – Biomass Gas & Electric (BG&E) filed petition to establish a docket regarding the proposed Forsyth County Renewable Energy Plant
    - August 2004 - Although a challenge to the avoided cost methodology was absent from BG&E's initial Petition, BG&E amended its Petition on August 26, 2004, asking the Commission to consider modifications of, or alternatives to, the avoided cost methodology that the Commission had approved in Docket No. 4822-U.
- February 18, 2005 – PSC rendered a decision in docket
    - Denied many of BG&E's requests
    - In its ruling, the PSC issued a directive for the establishment of a formalized process to address the "Proxy Unit Methodology" for the determination of avoided cost payments to QFs and renewables that operate similar to a base load facility.
- March 9, 2005 – PSC issued final order in docket

Phase 2 – Refining Georgia Power's Proxy Unit Price Methodology

- March 1, 2005 – PSC issued Procedural and Scheduling Order for subsequent phase
- May 27, 2005 – PSC Staff filed final Staff Report
- June 10, 2005 – PSC approved Georgia Power's proposed proxy unit methodology
    - PSC directed parties to conduct further discussions on which non-price factors could be considered for renewable resources (not paid in excess of avoided cost)
    - Order specified if no agreement could be reached, the PSC would decide
- July 14, 2005 – PSC issued Supplemental Order

Phase 3 – Details of Renewable QF Standard Offer Agreement Using Proxy Price Methodology

- March 10, 2006 – PSC issued Procedural and Scheduling Order
- June 28, 2006 – PSC issued final order resolving these issues

Georgia PSC Docket 39732 – Value of Solar and Renewables

The so-called Value of Solar docket represents a starting point in the journey that produced Georgia Power's Renewable Cost Benefit Framework. The docket kicked off with Georgia Solar Energy Industries Association ("GSEIA"), Vote Solar ("VS") and the Interstate Renewable Energy Council, Inc. ("IREC") July 10, 2014 petition requesting that the Commission establish and calculate the value of solar energy delivered to Georgia Power from customer-sited facilities. In turn, the Commission issued a Notice of Inquiry ("NOI") on August 10, 2015, soliciting public comment from all interested parties on the questions contained within the NOI related to renewable energy and distributed generation on Georgia Power's electric system. The Commission Staff reviewed the comments and organized a two-day workshop that took place in October 2015. The goal of the workshop was to identify points of consensus between the parties on the methodology to be used in determining the benefits and costs of renewable resources and distributed generation on Georgia Power's electric system and its retail customers.

On November 20,2105, the PSC Staff filed its draft report on the process to date, which made several recommendations, such that the IRP process should examine ways to reflect system-level costs and benefits of distributed generation and renewable energy resources that have not been captured to date, particularly avoided system losses and ancillary services. The Georgia PSC approved the staff report on January 19, 2016.

2021 Georgia PSC Avoided Cost Proceeding

During the 2019 Georgia Power Integrated Resource Plan proceeding, solar energy industry groups and clean energy advocates sponsored testimony examining the methodology Georgia Power uses to calculate its utility avoided cost. In its July 29, 2019, final IRP order, the Georgia Public Service Commission (PSC) endorsed a new proceeding to conduct a deeper review of this issue.

On March 11, 2021, the Georgia Public Service Commission (PSC) issued its final order in the 2021 Georgia Power Avoided Cost Proceeding (Dockets 4822 / 16573 / 19279), which incorporates a stipulation reached by Georgia Power and PSC Staff. The resolution of the case altered the existing avoided cost formula used by Georgia Power to calculate compensation for QFs in several ways. The final order:

- *Added Transmission and Distribution Loss Factors* – the Renewable Cost Benefit (RCB) Framework includes factors for Reduced Transmission Losses and Reduced Distribution Losses. These adjustment factors were added to the Avoided Cost formula for calculating prices paid to QFs under docket 4822 (i.e., standard-offer QFs). This change was proposed by Georgia Power and supported by intervenors.
- *Eliminated the Fuel Cost Multiplier* – the existing avoided cost formula included a Fuel Cost multiplier, which was used to adjust the Territorial Spot Fuel System Lambda value to capture the difference between spot fuel costs and the average costs of the total fuel portfolio. This multiplier was removed from the Avoided Cost formula for calculating prices paid to standard-offer QFs. This change was proposed by Georgia Power and opposed by PSC Staff and several other intervenors.
- *Added Support Capacity Production Costs (but Set at Zero Until Verified)* – the RCB Framework includes an adjustment for Support Capacity production costs. These costs are subtracted from the hourly avoided price paid to QFs. This cost adjustment was added to the Avoided Cost formula for calculating prices paid to standard-offer QFs, but the annual values was set at zero until the PSC Staff reviews actual Southern Company data and the Commission approves the data and methodology used in calculating the costs. At that time, the Support Capacity production cost values will be adjusted accordingly. This change was proposed by Georgia Power and opposed several intervenors. PSC Staff advocated for the costs to be set at zero until verified.

Utility Avoided Cost Practices – Electric Membership Coops and Municipal Utilities

There are 94 retail electric utilities in Georgia, including one investor-owned utility (Georgia Power), 41 electric membership cooperatives[1] (EMCs) and 51 cities and 1 county that operate their own electric utilities, so called

[1] This does not include Haywood EMC, headquartered in Waynesville, NC. Haywood serves a small slice of northern Rabun County in Georgia.

municipals or "munis." While the EMCs and munis in Georgia are largely not subject to regulation by the Georgia PSC, all are subject to the requirements of PURPA and must allow qualifying facilities to interconnect with their systems and compensate those providers at their avoided cost.

We found two examples of Georgia EMCs approach to PURPA utility avoided cost requirements:

- Sawnee EMC SCHEDULE QFPP-2
- Jackson EMC Rider NM

2. Methodology – Calculating Utility Avoided Cost

Industry Approaches to Calculating Utility Avoided Cost

This section is excepted verbatim or derived from two documents – the 2014 publication *PURPA Title II Compliance Manual*,[2] commissioned by a host of national trade associations including the American Public Power Association, the Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners (NARUC) and the National Rural Electric Cooperative Association (NRECA), and the 2006 publication *PURPA: Making the Sequel Better than the Original*,[3] commissioned by EEI.

Intro

States took advantage of the ample flexibility afforded them under FERC's PURPA regulations and proceeded to establish many different methods of calculating avoided costs for the purpose of setting QF purchase rates. These methods have generally satisfied FERC requirements and have been in use for many years. A couple of noteworthy considerations include:

- *Administrative vs market pricing*: Nearly all the early approaches involved an administrative determination of avoided cost. That is, avoided cost was determined based on utility- or state-developed projections of the utility's incremental energy and capacity costs. Requests for Proposals (RFPs) or competitive procurement were not used initially to determine avoided costs. This came later with the growth of wholesale competition.

- *Short-Term vs Long-Term Avoided Costs*: In some cases, states established different methods to calculate short-term avoided costs and long-term avoided costs.

    - Short Term - Payments based on a utility's short-term avoided cost typically were provided to QFs that sold energy on a non-firm or "as available" basis and were based on the utility's actual or forecasted hourly incremental or marginal cost of energy (such as system lambda).
    - Long-term contracts with fixed prices required long-term estimates of avoided cost. A variety of methods was used to develop such estimates, including: (1) the proxy unit or committed unit approach, (2) the component or "peaker" approach, (3) differential revenue requirement, and

[2] Burns, Robert and Kenneth Rose, 2014. *PURPA Title II Compliance Manual.* Available at https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC.

[3] Graves, Frank, Philip Hanser, Greg Basheda for the Edison Electric Institute, 2006. *PURPA: Making the Sequel Better than the Original.* Available at https://puc.sd.gov/commission/dockets/electric/2011/EL11-006/puctestimony/roundsexhibit1.pdf.

(4) variants of these methods including expansion planning (generation resource plan) approaches.

Following is a brief description of the most relevant avoided cost approaches:

Proxy Unit / Resource Method

The proxy or committed unit approach assumes that a QF enables a utility to delay or displace its next planned generating unit. As a result, the utility's avoided costs are based on the projected capacity and energy costs of this next planned generating unit. The proxy unit's estimated fixed costs (annualized over the expected life of the unit to yield annual capacity cost per kW) set the avoided capacity cost and its estimated variable costs set the avoided energy cost.

This approach does not require the use of production cost or other models because avoided costs are unit specific and do not depend on the utility's system marginal energy cost at any given time. The proxy unit approach should, however, account for any differences in the in-service date of the QF and of the proxy unit. This was typically done either by not providing the QF a capacity payment until the time the proxy unit would have come online or by discounting the lump sum present value of the capacity payments at the time value of money so that customers (in theory) would be financially indifferent between the two payment streams.

"Peaker" or Component Method

Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. Capacity payments are provided only if the utility needs capacity and are set equal to the lowest-cost capacity option available to the utility, typically a peaking unit (e.g., combustion turbine). Energy payments are based on the utility's system-wide marginal or avoided energy cost (not the energy cost of a peaker unit, which is typically more expensive). This method assumes that a QF, rather than displacing or delaying the need for a particular generating unit, allows the utility to reduce the marginal generation on its system and to avoid building a combustion turbine of the same size as the QF.

This approach is data-intensive, as it requires the use of a production cost simulation model to estimate the utility's system marginal energy costs with and without the QF in its resource portfolio. Through such modeling, detailed, time-differentiated avoided energy and capacity costs are developed for each year of the QF contract term.

Differential Revenue Requirement Method

Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF. The differential revenue requirement approach assumes an amount of QF capacity operating with given characteristics and calculates the utility's total generation cost (revenue requirement) with and without that QF capacity over a period of years, assuming that the QF energy and capacity are free. This "free" QF output reduces the utility's revenue requirement. The present value of the difference in total generation costs between the two cases is the lump sum of avoided cost for the hypothetical block of QF power. This method essentially calculates both energy and capacity (when required) cost simultaneously.

The differential revenue requirement method requires the use of two types of models. A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QFs are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes).

Auction/RFP rates

Auctions, or bidding, programs were used by several states beginning in the late 1980s. If a utility required capacity, the utility would issue an RFP specifying the type of capacity needed and the selection criteria. Winning projects were selected according to price and other explicit factors. These factors were similar to "factors affecting rates for purchase" that FERC outlined and are listed above. Successful bidders receive capacity contracts; unsuccessful QF bidders may sell energy at avoided energy costs as required under PURPA, but not receive a capacity payment.13

These programs varied from state to state on how involved the commission was in the design and application of the bidding program. Some states had highly prescriptive evaluation criteria and qualification of the bidders that utilities were required to follow, while other states gave the utility a great deal of discretion. In some cases, the utility was allowed to participate in process as a bidder.

Georgia - 1994 Docket 4822 Final Order

In its 1994 final order in Docket 4822, the Georgia PSC made the following determinations about avoided energy and capacity pricing:

Avoided Energy

The Georgia PSC declared that the appropriate components for calculating utility avoided energy cost are:

- territorial system lambda[4],
- a marginal cost multiplier (to account for the difference between system lambda calculations and actual avoided energy costs)
- a marginal cost fuel multiplier (to reflect the difference between spot fuel costs used for economic dispatch and the average of the total fuel portfolio costs excluding non-fossil fuels and contracts not entered into within the prior five years – the multiplier is greater than one when spot fuel prices are less than average fuel prices)
- avoided O&M costs,
- avoided environmental costs and
- avoided startup/commitment costs.

The following formula shall be used to determine qualifying facility avoided energy cost prices:

[4] GPC and Savannah Electric insisted that Southern Company "system lambda" be understood as Southern "system territorial lambda," because system lambda includes off-system sales by any of the utilities on the system and so would overstate avoided cost.

$$\text{QF avoided energy costs price} = \begin{array}{c} \text{(utility system lambda)} \\ \times \text{ (marginal cost multiplier)} \\ \times \text{ (average fuel portfolio cost) / (spot market fuel cost)} \\ + \text{ (avoided O\&M costs)} \\ + \text{ (avoided environmental costs)} \\ + \text{ (avoided start-up costs)} \end{array}$$

Avoided Capacity

The Georgia PSC declared that the utilities shall follow the peaker approach to calculate avoided capacity costs for the purpose of payments to QFs. The capacity cost payments shall be calculated by the avoided Economic Carrying Cost (ECC) of the peaking resources including the following avoided capacity cost components: capital cost, fixed O&M, capital additions, fuel inventory, O&M adders, and transmission. The capital cost component shall be fixed, and the other five components should be indexed to actual future prices.

Georgia – Understanding Southern Company's System Lambda

Southern Company "system lambda" plays a central role in the valuation of renewable energy in Georgia. So, what is system lambda? In general terms, system lambda represents the cost of the next kilowatt hour that could be produced from economical dispatchable units on a discrete electricity system (a system including interconnected electrical generating units, transmission lines, substations and distribution networks). Another way to express it is that when a system uses economic dispatch, the cost of the very last generating plant needed to supply power in each hour sets the system lambda for that hour.

Any electric utility that operates a balancing authority area[5] and/or planning area must complete FERC Form 714 each year. Form 714 gathers utility operating and planning information, including historic hourly system lambda values. As part of the filing, utilities are required to provide their definition of system lambda used in calculating the hourly values submitted to FERC.

In its 2018 filing, Southern Company provided this description of its system lambda calculation:

> The Southern Company system lambda is determined hourly and is based on the variable costs of the resources that serve the load obligations of the Operating Companies plus any sales to third parties.[6] The variable costs of the resources include the components listed below and may also reflect the cost of purchases. The economic dispatch formula used to dispatch Southern's generating resources on the basis of their variable cost components is as follows:
>
> l = [{ (2aP + b) * (FC + EC) } + VOM + FH] * TPF

[5] At the highest level, the US power system is made up of three main interconnections. Each of these interconnections are made up of some number of balancing areas. For instance, the Eastern Interconnection covers about half of the US and parts of Canada and consists of 36 balancing areas. Within each balancing area, a single entity is responsible for a series of coordination activities, such as load balancing, dispatching power plants, managing interchanges with other balancing areas, etc.

[6] Note – this definition may differ from "territorial system lambda" as used in Georgia Power's avoided cost calculation. See footnote 4.

Where:

l	= System lambda
a, b	= Incremental heat rate coefficients
P	= Generation level
FC	= Marginal replacement fuel costs
EC	= Marginal replacement emission allowance costs
VOM	= Variable operations and maintenance expenses
FH	= In-plant fuel handling expenses
TPF	= Incremental transmission losses (penalty factors)

In the 2021 Avoided Cost docket, Georgia Power provided numerous data requests that defined several variations of Southern Company System lambda. Figure 2 provides a brief overview of these system lambda variations.

FIGURE 2. COMPARISON OF SOUTHERN COMPANY SYSTEM LAMBDA VARIATIONS

Title	Role in 2021 AC Docket	DR	Timing	Notes	Marginal Unit Fuel	Variable O&M	Emissions	Trasmission Losses	Off-System / Opp'ty Sales
SoCo Territorial Spot Fuel Lambda	Used in 1994 AC formula	STF-4-6	Day ahead projection	Is the "fuel component of bottom of stack ("BOS") system lambda, separated out for compensating QFs." Only available in this format as a day ahead projection.	✓				
Bottom of the Stack Lambda	Used in new (2021 and beyond) AC formula	STF-4-12	Day or hour ahead projection	Also used as basis for RTP pricing; used for DSM cost/benefit analysis	✓	✓	✓		
Associated Interchange Energy Rate ("AIER")	Minimal - in contract revision related to compensation for energy sold by QF during testing.	Rate Case PIA-4-9	Backward looking	Backward looking for pool settlement purposes per Intercompany Interchange Contract (IIC). STF-6-4 confirms AIER rate is same as backward-looking BOS lambda. STF-7-12 addresses trans. losses.	✓	✓	✓	✓	
Top of the Stack Lambda	None	STF-4-8	Projection	GPC says consistent with FERC 714	✓	✓	✓		✓
FERC 714	None	STF-4-17	Projection	Same as STF-4-8 (TOS lambda); GPC says used on SoCo trading floor	✓	✓	✓		✓

Georgia - Docket 19279 (2004 – 2006)

In July 2004, Biomass Gas & Electric (BG&E) filed a petition to establish a docket regarding its proposed Forsyth County Renewable Energy Plant. Although a challenge to the avoided cost methodology was absent from BG&E's initial Petition, BG&E amended its Petition on August 26, 2004, asking the Commission to consider modifications of, or alternatives to, the avoided cost methodology that the Commission had approved in Docket No. 4822-U.

The docket unfolded in three phases over two years. The primary results were:

1. The Georgia PSC approved the use of "Proxy Unit Methodology" for the determination of avoided cost payments to QFs and renewables that operate similar to a base load facility, and
1. The Georgia PSC approved a "Renewable QF Standard Offer Agreement Using Proxy Price Methodology."

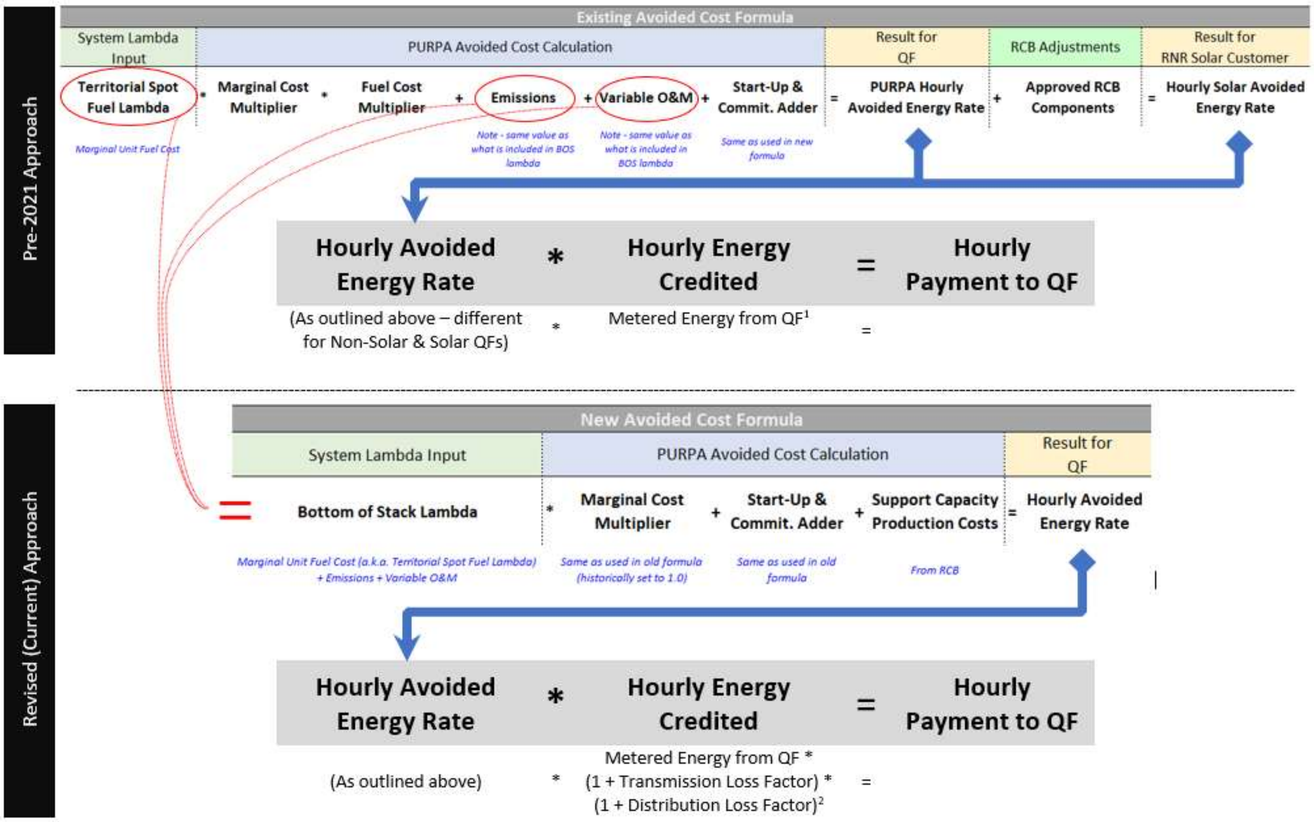
Georgia – 2021 Avoided Cost Proceeding (Dockets 4822 / 16573 / 19279)

As described in Section 1, the Georgia PSC conducted a review of Georgia Power's avoided cost methodology. On March 11, 2021, the Georgia Public Service Commission (PSC) issued its final order in the 2021 Georgia Power Avoided Cost Proceeding. This ruling changed the calculation of avoided cost for standard offer QFs in several ways, including:

- *Added Transmission and Distribution Loss Factors* – the Renewable Cost Benefit (RCB) Framework includes factors for Reduced Transmission Losses and Reduced Distribution Losses. These adjustment factors were added to the Avoided Cost formula for calculating prices paid to QFs under docket 4822 (i.e., standard-offer QFs). This change was proposed by Georgia Power and supported by intervenors.
- *Eliminated the Fuel Cost Multiplier* – the existing avoided cost formula included a Fuel Cost multiplier, which was used to adjust the Territorial Spot Fuel System Lambda value to capture the difference between spot fuel costs and the average costs of the total fuel portfolio. This multiplier was removed from the Avoided Cost formula for calculating prices paid to standard-offer QFs. This change was proposed by Georgia Power and opposed by PSC Staff and several other intervenors.
- *Added Support Capacity Production Costs (but Set at Zero Until Verified)* – the RCB Framework includes an adjustment for Support Capacity production costs. These costs are subtracted from the hourly avoided price paid to QFs. This cost adjustment was added to the Avoided Cost formula for calculating prices paid to standard-offer QFs, but the annual values was set at zero until the PSC Staff reviews actual Southern Company data and the Commission approves the data and methodology used in calculating the costs. At that time, the Support Capacity production cost values will be adjusted accordingly. This change was proposed by Georgia Power and opposed several intervenors. PSC Staff advocated for the costs to be set at zero until verified.

Figure 2 attempts to describe the changes from the pre-2021 standard offer avoided cost calculation and the one now in force at the Commission.

FIGURE 3. SIDE-BY-SIDE COMPARISON OF PRE-2021 AND NEW GEORGIA PSC AVOIDED COST FORMULA



[1] Not certain if the metered energy is adjusted by RCB energy components for solar QFs, as is depicted in this step for the new approach.
[2] The transmission and distribution loss factors are technology specific. The proposed technology categories are: (a) Non-Intermittent, (b) Solar BTM DG; (c) Solar Ground-Mounted Tracking; (d) Solar Ground-Mounted Fixed Tilt; and (e) Wind.

3. Qualifying Facilities in Georgia

What is a Qualifying Facility?

Qualifying facilities (QFs) fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities:

- A small power production facility is a generating facility of 80 MW[7] or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources.
- A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. There is no size limitation for qualifying cogeneration facilities. [8]

There are additional limitations to qualification:

[7] The 80 MW limit is generally applied to the whole facility, not individual generators. For further detail, refer to 18 C.F.R. § 292.204(a).
[8] Federal Energy Regulatory Commission (September 2019). *What is a Qualifying Facility?,* available at https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp.

- Fundamental Use Test - A facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.[9]

GPC Purchases from Cogenerators and Small Power Producers

Georgia Power files monthly reports on purchases from cogenerators and small power producers that operate under one of Georgia Power's PURPA-oriented "standard offer" agreements (filed under Georgia Public Service Commission Docket #1). The universe of QFs in Georgia is larger, of course, including QF operating under different contractual arrangements with Georgia Power and operating in the service territories of other Georgia utilities, but this list offers a useful snapshot of QFs in Georgia. These reports show energy and capacity payments to 30 – 33 cogenerators and small power producers over the last two years. We know this group of qualifying facilities includes some cogenerators and solar small power producers, such as:

- Cogenerators
  - International Paper's Port Wentworth Mill – 2 units totaling 73 MW, fueled by black liquor
  - Graphic Packaging International Augusta Mill – 3 units totaling 84 MW, fueled by wood waste and natural gas.

- Small Power Producers
  - Landfill Gas
    - Richland Creek Landfill, Buford, GA (Gwinnett County) (10.9 MW), including five 2.2 MW reciprocating engine units[10]
    - Pine Ridge Landfill, Griffin, GA (Spalding / Butts County) (6.6 MW), including three 2.2 MW reciprocating engine units[11]
    - Oak Grove Landfill, Winder, GA (Barrow County) (6.6 MW), including three 2.2 MW reciprocating engine units[12]
  - Solar
    - Chatsworth Water – 1 MW ground-mount solar array
    - MARTA Laredo Bus Maintenance Facility – 1.2 MW solar canopy
    - IKEA Atlanta – 1.03 MW rooftop solar array
    - IKEA Savannah – 1.45 MW rooftop solar array

Appendix A contains a profile of the Chatsworth Water facility.

2019 IRP Hearing Request Set Number 2

In response to a solar industry hearing request during the 2019 IRP, Georgia Power provided a summary of the numbers of solar qualifying facilities operating in its service territory. In its response, Georgia Power used the broad definition of solar QF – anything less than 80 MW – and disaggregated the total by contract type. This response provides limited insight but does reflect the relatively low number of systems operating under

[9] Federal Energy Regulatory Commission (April 2019). *FERC Form 556*. Available at https://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf.
[10] LMOP database
[11] LMOP database
[12] LMOP database

qualifying facility standard offer agreements (6) and the relatively large number of systems operating under power purchase agreement pursuant to the ASI, ASI-Prime or REDI procurement programs. This response provided no detail about specific QFs.

Table 4. QF Table from Georgia Power's 2019 IRP Hearing Request Response

# of QFs	Contract Type	Capacity (MWAC)
913	RNR	9.8
813	No contract (Energy Offset Only*)	10.8
475	Advanced Solar Initiative (ASI) & ASI-Prime	510.1
33	Renewable Energy Development Initiative (REDI) Distributed Gen.	36.1
16	Solar Purchase (SP)	0.2
6	QF Standard Offer	5.6
5	Large Scale Solar & Green Energy	51
2,261	TOTALS	623.6

*Represents customer generators known to Georgia Power who do not sell the energy output to Georgia Power through any form of a power purchase agreement. Some project sizes are either unknown or conservatively assumed.

Project Description

In 2015, Chatsworth Water Works Commission built a 1-megawatt AC ground-mount solar array in a field between the utility's main office building and its Judson Vick Wastewater Treatment Plant (WWTP). The array began producing electricity in November of that year and provides energy to both the WWTP and office building. Georgia Power served as the consulting engineer and designed the project. The Georgia Environmental Finance Authority provided a $2.1 million dollar loan to finance the project, including a reduced interest rate and $300,000 in "principal forgiveness."

The system was designed to exceed Chatsworth's immediate power needs and allow the Commission to sell power back to Georgia Power. The General Manager estimates that, even after the Commission optimizes its load to take advantage of peak solar production, the Commission sells back 40 - 50 percent of the electricity its solar array generates each month.

Contractual Terms

In October 2015, Chatsworth Water signed a "Contract for the Purchase of Non-Firm Energy from a Qualifying Facility" with Georgia Power. As such, the Commission is paid the utility's hourly avoided energy cost for power it sells to the utility. Chatsworth receives no payments for capacity.

At the time it began operation of the solar array, the Commission also switched the tariffs for their WWTP and office building to Georgia Power's Time of Use – General Service Demand (TOU-GSD-10).

Solar Compensation

Chatsworth receives a simple monthly compensation statement that includes (a) meter read begin and end dates; (b) total monthly generation in kWh; (c) gross monthly compensation; (d) administrative fee; and (e) net monthly compensation. Table 1 shows a summary of the compensation Chatsworth received for its solar exports during 2019. Figure 1 reflects the pre-fee and post-fee average monthly unit cost.

Table 1 – Monthly Solar Compensation for Chatsworth Water Works Commission

Month	QF Exported Generation (kWh)	Gross Compensation	Admin Fee	Net Compensation	Average Unit Price (cents per kWh) Before Admin Fee	After Admin Fee
Jan-19	48,313	$1,110.86	$100.00	$1,010.86	2.3	2.1
Feb-19	33,534	$703.90	$100.00	$603.90	2.1	1.8
Mar-19	88,569	$2,491.87	$100.00	$2,391.87	2.8	2.7
Apr-19	89,059	$2,528.27	$100.00	$2,428.27	2.8	2.7
May-19	33,491	$1,104.96	$100.00	$1,004.96	3.3	3.0
Jun-19	57,477	$1,699.78	$100.00	$1,599.78	3.0	2.8
Jul-19	85,315	$2,857.57	$100.00	$2,757.57	3.3	3.2
Aug-19	101,243	$3,316.08	$100.00	$3,216.08	3.3	3.2
Sep-19	85,137	$2,948.00	$100.00	$2,848.00	3.5	3.3
Oct-19	57,020	$1,625.32	$100.00	$1,525.32	2.9	2.7
Nov-19	59706	$1,583.07	$100.00	$1,483.07	2.7	2.5
Dec-19	36,588	$701.80	$100.00	$601.80	1.9	1.6

Figure 1 – Monthly Average Unit Price Received Solar Exports by Chatsworth Water Commission