BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

	:	
In Re:	:	
		DOCKET NO. 36989
Georgia Power Company's 2013 Rate Case	:	
	:	

DIRECT TESTIMONY

OF

KARL R. RÁBAGO

Presented on behalf of the
Georgia Solar Energy Industries Association

OCTOBER 18, 2013

Galloway & Lyndall, LLP
The Lewis-Mills House
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Q. Please state your name and business address.

A. My name is Karl R. Rábago. My business address is 8904 Granada Hills Drive, Austin, Texas.

Q. By whom are you employed and in what capacity?

A. I am the principal of Rábago Energy LLC, a Texas limited liability company.

Q. Detail your education and work experience.

A. My education and work experience are set forth in detail on my resume, attached as Exhibit KRR-1. I provided an extensive description of my education and work experience in my prefiled testimony in *In re: Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification of Plant Branch Unit 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6*, Docket No. 36498 ("the IRP Docket"). There have been no significant changes in my education and work experience since that time. My prior testimony in the IRP Docket about my work experience is incorporated herein by reference.

Q. Have you previously submitted testimony before the Georgia Public Service Commission ("the Commission") or other state or federal bodies?

A. Yes. I appeared as an expert witness on behalf of the Georgia Solar Energy Industries Association ("GSEIA") in the Commission's recent IRP Docket. I have also testified before several state regulatory agencies, including the North Carolina Utilities Commission, the Louisiana Public Service Commission, and the Michigan Public Service Commission. I have testified before Congress and state legislatures, most recently the Minnesota State Senate and House of Representatives.

Q. What is the purpose of your testimony in this proceeding?

A. Through its proposed Supplemental Power Service-1 tariff ("SPS-1") and correlated changes in other tariff provisions, Georgia Power Company ("the Company") seeks to impose new rates and charges on customers who install and use solar energy generation systems at their homes, businesses and farms. In my testimony, I urge the Commission to deny these new charges because the Company has failed to substantiate its need to implement tariff charges that unreasonably discriminate against this particular customer class. The rates and charges contained in SPS-1 and correlated time of use ("TOU") tariffs are not just or reasonable. Therefore, their implementation is not in the public interest.

In lieu of approving the Company's SPS-1 tariff (and its progeny), I provide additional testimony here (supplementing my testimony in the IRP Docket) on how the Company should examine the value of distributed solar energy or Value of Solar ("VOS"). I recommend that the Company be directed to develop VOS avoided cost calculations consistent with my recommendations in a separate proceeding, a transparent process which will include Commission staff and solar industry stakeholders and will fully justify any requested rates or charges the Company desires to apply to its customers who deploy solar energy.

Q. What materials did you review in preparing your testimony?

A. In addition to the materials cited in and included as Exhibits to my testimony, I reviewed documents submitted by the Company in this docket relating to rates and charges for solar customers and the transcript of direct and cross examination testimony of Messrs. O'Sheasy and Roberts.

SOLAR-RELATED RATES AND CHARGES

Q. For purposes of your testimony, who is a "solar customer" of the Company?

A. A "solar customer," as I use the term here, is a customer of the Company who deploys solar generation on their property for their own use. Solar deployment permits the solar customer to exercise some level of individual control over their electric usage. Solar generation is used by the solar customer to reduce the amount of electricity that must be purchased from the Company.

However, the solar customer's premise remains connected to the Company's grid, and almost all solar customers continue to purchase electricity in some amount from the Company. The Company's proposed SPS-1 and correlated TOU tariff charges will apply to solar customers.

Q. Does SPS-1 apply only to solar generation?

A. The Company proposes to apply SPS-1 to any customer that deploys distributed behind the meter generation. However, all of the Company's calculations and justifications for SPS-1 derive from solar generation.

Q. What does the Company propose to do with respect to rates for solar customers?

A. The Company proposes:

1. For the first time to impose explicit demand charges on residential customers who deploy solar generation;

2. to make the Time of Use - Residential Energy Only (TOU-REO) and Time of Use - Plugin Electric Vehicle (TOU-PEV) tariff offerings unavailable to residential customers who deploy solar generation, absent paying a monthly capacity charge;

3. to reduce substantially the tariff options available to commercial customers who choose to deploy solar generation; and

4. to deprive commercial customers who deploy solar generation of generally favorable TOU rates.

Q. Is SPS-1 a true tariff?

A. No. With the exception of a capacity charge option for R-20 (residential), Time of Use-Residential

Energy Only (TOU-REO), Time of Use-Plugin Electric Vehicle (TOU-PEV) and Farm Service (FS) customers, SPS-1 contains no rates or charges.

Q. How does SPS-1 apply to solar customers?

A. With the exceptions noted above, SPS-1 refers solar customers to the tariff that will apply to them. For example, a small business customer may be on the GS-8 tariff now. When that customer deploys a solar facility on premise, SPS-1 requires the customer to obtain service under the PLS-9 tariff. The rates that the customer will be charged are set forth in PLS-9, not SPS-1. For the exceptions noted, customers on the R-20, TOU-REO, TOU-PEV and FS tariffs can stay on their current tariff after they deploy solar and pay an additional $5.56 per kW name plate capacity charge imposed under SPS-1.

Q. Are the proposed charges and rates under SPS-1 understandable and usable by solar customers?

A. No, the SPS-1 process is unnecessarily complex. Though SPS-1 and its correlated TOU tariff changes technically apply to any means of on-site generation, they appear primarily intended to frustrate and confuse potential solar customers. Potential solar customers must evaluate a wide range of factors to understand how SPS-1 and its correlated TOU tariffs impact them in their effort to achieve an optimal economic position from which to consume and generate electricity. Under SPS-1, solar customers must evaluate:

Energy consumption factors,

Peak and average demand,

Solar generation system size and cost in kilowatts,

Solar generation system energy output, and

The bill impact associated with the TOU and SPS rates and charges.

In addition, potential solar customers face changes in these factors due to changes in the Company's avoided cost and capacity-related charges. The solar customer must then navigate a maze of interlocking and cross-referencing tariffs. For commercial solar customers, the new rate structures limit the menu of rate options from which they could choose – before they became solar customers. The new SPS-1 rate structure appears designed to punish or limit customer choice of solar generation for their homes or buildings, all without substantiation or cost analysis.

Q. What are your findings regarding the SPS-1 tariff?

A. SPS-1 and its correlated TOU tariff changes appear to impose a specific capacity-denominated energy charge levied on the Company's solar customers. The Company assumes that solar customers cause the Company to experience unrecovered revenues associated with solar generation intermittence. The Company apparently conducted an internal avoided cost calculation without the benefit of a cost of service study. Then, the Company applied an arithmetic calculation matching a solar customer's economics with the Company's calculation results to derive "Expect Savings," a kind of solar avoided cost. In the absence of any historical test year data relating to actual costs, it appears that the Company seeks to establish a new rate structure – specifically, anticipatory capacity or demand fees – that it will impose on solar customers to recover unsubstantiated alleged shortfalls in revenue. SPS-1 and its correlated TOU tariff rate increases are an anticipatory true-up. Based on my experience, I do not believe that the rate process established in SPS-1 and its correlated TOU tariffs would pass regulatory muster in jurisdictions with which I am familiar.

Q. What is a demand charge imposed by a utility?

A. Traditional utility ratemaking depends on analysis of costs and allocation of those costs into cost categories. Those cost categories are then allocated to customer classes based on cost allocation procedures to determine class revenue requirements. These revenue requirements are then translated into rates and charges.

The major categories of costs for allocation are energy and demand or capacity. Capacity or demand costs derive from mostly fixed costs that are associated with plant in service to serve customers regardless of the amount of energy the customer consumes. Capacity or demand charges are collected with fixed charges such as customer charges or through demand-based charges based on demand for capacity on a per kW basis. Energy-related costs are typically variable and are volumetric in nature -- they vary with the level of energy use and are typically collected through variable charges for each kWh of energy use.

Q. How are demand costs typically recovered?

A. Because of the wide variation in demand for capacity and energy in customer classes, average rates derived from class-wide cost data are calculated and used to recover both energy and demand costs. For residential customers, volumetric rates for both energy and demand costs are appropriate given the relative uniformity and smaller scale of demand for capacity among members of the rate class. Residential rates seldom if ever include demand charges or separate demand-based adders because it is fairly easy to forecast residential class demand. Actual demand does not vary significantly from forecasts. Measured solar customer load shapes conform highly to other non-solar customer load shapes. As a result, they rest neatly within the bounds of accurate load forecasting.

For larger commercial and/or industrial customers, there is greater range of variability in demand costs. There, utilities typically use a rate that separately charges an average energy rate and a demand charge for capacity appropriate to the customer class and based on cost causation. For example, even though justification for TOU rates is that system-wide demand costs are higher during certain time periods, these costs are typically translated into time-based energy charges for smaller customers. Regardless of how the costs are recovered, the costs should be substantiated through a cost-of-service study and cost allocation procedure.

Q. How does the proposed SPS-1 tariff square with the traditional practice of setting rates for demand or capacity related costs?

A. The proposed SPS rate is unusual and suspect as a matter of sound ratemaking. As best I can determine, the Company used the following steps to set capacity charges under SPS-1 and its correlated TOU tariffs:

a. The Company combines hourly marginal energy costs from its 2013 RTP forecast with solar production assumptions to derive a load-weighted system lambda for solar generation.

b. The Company combines the load weighted system lambda for solar energy with hypothetical solar system output values based on a system located in Atlanta to establish a solar avoided cost that it calls the "Expected Savings." The Expected Savings is adjusted upward very slightly from a pure energy value with extremely limited values associated with some transmission, distribution, and environmental costs, all framed within the unusually short time period of three years, which coincides with the rate setting period in this proceeding. Presumably, this is what the Company deems a solar system "saves" the utility in terms of value, though the savings are severely constrained.

c. The Company then subtracts the "Expected Savings" from what it calls the "Current Savings," or the value of bill offsets that the solar customer would experience in the absence of the SPS-1 based charge.

d. The Company then labels the difference between "Current Savings" and "Expected Savings" as the "Difference" - a number that represents the Company's presumed shortfall in revenue recovery. It is important to note that the Company offers no analysis or evidence of value from distributed solar beyond the short-term and limited "Expected Savings." Nor does it explain how the value was selected.

e. The Company then uses the "Difference" between net bill offset that would have been experienced by a solar customer and the low, energy-based value from distributed solar to calculate how much of a charge it would have to apply for each kW of solar to be kept whole. While the charge is levied per kW of solar installed capacity, it appears to be derived only from energy value and the gross customer rate. The charge is not derived from measured solar generation or energy consumption of the solar customer.

Q. Why is this process unusual and suspect?

A. It is unusual to establish a charge for a cost for which there is no evidence. Furthermore, the rate appears designed to recover what the Company considers a revenue shortfall (the "Difference") without evidence that the Company actually incurred any revenue shortfall. SPS-1 raises the suspicion that the Company seeks to chill the growth of distributed solar generation (“DSG”) in Georgia and deny customers the opportunity to manage their energy costs through their own customer investment in solar generation systems.

Q. Do you have any other reasons to believe that SPS-1 tariff is unusual?

A. A review of questions from the Commissioners to Company witnesses Roberts and O'Sheasy provides modest additional information on SPS-1, as follows:

a. The Company views solar generation as having little more than energy value evidenced by the use of hourly marginal energy prices matched against hypothetical solar production in Atlanta. Mr. Roberts went so far as to imply that solar energy provides no capacity value because the Company has a system peak at or near 7:00 p.m.[1] The Company's data filed with the Federal Energy Regulatory Commission ("FERC") covering the four summer months (JUN-SEP) for 18 years show only one instance where the system peaked during the hour ending as late as 5:00 p.m., with all other monthly summer peaks occurring between the hours ending 2:00 p.m. to 4:00 p.m. (Exhibit KRR-2) According to the Company's FERC data, the system peaks when solar generation is still operating. This implies an effective load carrying capability for DSG that creates significant capacity value.

b. The Company assumes that to the extent solar generation causes a customer to see a bill reduction in excess of the energy value, the Company is losing revenues required to pay for capacity and infrastructure. This assumption is flawed because of the likely contributions to the system energy and peak demand that the solar customer is providing. The Company's assumption lacks data or analytical substantiation.

c. The Company assumes that the hypothetical revenue shortfall is fully allocable to solar customers and fully

[1] T. 698.

correlated to non-energy costs. Therefore, it seeks to create a new structure of rates and customer charges, forcing solar customers to accept capacity charges under a TOU rate. The Company also reduces TOU rate options for commercial customers.

d. The Company assumes that solar customers are standby or supplemental service customers even though solar customers use utility generated electricity every day. Solar customers' usage characteristics are not typically associated with standby and supplemental service. Such charges are typically reserved for customers with very large loads and large self-generation systems that can suddenly trip offline. In fact, SPS-1 replaces the Company's Back-Up ("BU") tariff that was designed for large cogeneration customers, not residences and small businesses.

DSG systems have none of these characteristics. Even when clouds reduce solar production, the utility experiences a correlative reduction in demand. Given that most DSG systems primarily serve on-site load, they ultimately appear to the utility to have ordinary non-solar customer variability in consumption levels. Imposing a standby charge on distributed solar is like charging customers for changing set points on their air conditioner thermostat during the day or charging customers for using automatic light dimmers that reduce load in direct correlation to solar generation. I am not aware of any precedent for imposing customer-specific capacity charges like these. I see no reasonable basis to penalize solar customers for deploying a technology that performs in essentially the same manner as common energy efficiency measures to reduce load.

e. The Company characterizes the net consumption pattern of solar customers as uniquely intermittent and variable, though it produces no evidence that these patterns are materially different from those associated with normal operations of homes or businesses with air conditioner and other major loads. The Company fails to demonstrate that the load reduction or other effects of solar are any more variable than any customer-side load reductions or increases associated with, for example, demand-side technologies.

f. The Company assumes that the three (3) year perspective of the rate case is the appropriate lens through which to evaluate VOS, despite the fact that solar systems typically operate reliably for 25 years or more.

Use of a three (3) year period to calculate VOS results in lower value.

g. Finally, the Company asserts that solar customers do not pay the full costs that they cause the system, with the result that costs are shifted from solar customers to other ratepayers. Presumably, SPS-1 is intended to eliminate this cost shift. If this were really the case, the Company's rates for other ratepayers should be correspondingly reduced. Despite imposing SPS-1 on solar customers, the Company proposes no corresponding rate reduction for other ratepayers.

Q. Do distributed solar systems provide capacity value to the Company and its ratepayers?

A. Yes. Based on the information about the Company's system peak, solar energy systems provide capacity value every day that they operate. When DSG systems do not operate due to persistent cloudy weather, system-wide demand is also substantially lower. The Company should evaluate the effective load carrying capability of solar generation using time-differentiated analysis of solar production and system capacity requirements. As I explain later, the Company should also fully investigate VOS considering other factors and/or values that may have been overlooked or minimized by it in preparing the SPS-1 tariff.

Q. Based thereon, what is your opinion of the Company's concerns about revenue shortfall?

A. First, I emphasize that there may be no revenue shortfall at all. As explained below, several properly conducted VOS studies show value in excess of retail rates. In that case, solar customers may be subsidizing the Company and other ratepayers, and they may be entitled to a credit. Even if the Company's unmeasured revenue assumptions are partially true, the amount thereof does not justify the Company's proposed anticipatory true-up through the SPS-1 and its correlated TOU rate changes. My primary point is that any revenue impact must be substantiated by appropriate measurement and analysis.

Q. How do SPS-1 and TOU-RD-1 proposed by the Company compare with the rates you designed and implemented at Austin Energy?

A. Though Austin Energy's rates were cited by the Company during testimony in the IRP hearing, there are several key differences between Austin Energy's program and SPS-1 and its correlated TOU tariffs.

These differences, taken together, suggest that SPS-1 seeks to discourage customers exercising the choice to invest in DSG systems.

For commercial customers up to 200 kW, Austin Energy utilizes a performance based incentive ("PBI") in conjunction with net metering which provides an incentive payment of $0.11/kWh for a term of ten years. PBI was designed with consideration of the calculated VOS of $0.128/kWh. It allows commercial customers to realize the bill savings that come through net metering, but it also preserves rate structures in place for similarly situated non-solar customers. Austin Energy does not limit base rate options when a customer chooses to install a DSG system.

For residential customers, Austin Energy transitioned customers from traditional net metering to the VOS rate. The change involved first calculating a full VOS at a 30-year levelized value that sums energy, capacity, transmission and distribution, line loss, and environmental values provided by solar generation. In rates, customers are credited for all solar generation at the VOS of $0.128/kWh, which is revisited and reset annually. To eliminate risk of cross-subsidy, customers are also charged for gross consumption at the otherwise applicable residential rate of about $0.10/kWh. The utility recovers any shortfall between the VOS and the retail rate through the fuel reconciliation charge. In this manner, the customer is compensated fairly for the full value that their solar generation provides to the utility and the ratepayers, and the utility fully recovers its revenue requirement. Customers enjoy the opportunity to choose solar generation for their energy needs, and the utility receives the substantial benefits of local solar generation without cross subsidies or upward pressure on rates. The VOS rate has been successful so far, allowing a vibrant solar market to grow at an accelerated pace.

Austin Energy's policies have led to the installation of more than 2,000 solar systems and the creation of some 600 direct solar industry jobs in a community of about 1 million. This success has been founded on principles of fairness and choice for customers, transparency and engagement on methodologies and program development, and a culture of market-based innovation and leadership. Austin Energy’s process contrasts significantly with the Company’s development of SPS-1.

Q. How does SPS-1 compare to the Company's demand-side programs?

A. It is my understanding that the Company does not pre-charge customers for reduced revenue related to demand side management or efficiency, instead opting for an after-the-fact true up and reconciliation of impacts caused by efficiency programs. The Company does not charge individual customers for using demand side programs and technologies. Instead, the Company spreads DSM program and other costs to all customers, consistent with fact that demand side resources generate value for all customers. DSG provides similar demand side benefits.

Q. Is solar generation a demand-side technology?

A. Like other demand-side resources, DSG is paid for and maintained by the solar customer, providing electricity to the utility at a significantly lower cost than the utility incurs for its own generation. Solar generation peaks with sunshine. Sunshine, in air conditioning-dominated electric systems, drives peak demand. This means solar output is highly correlated with system generation, transmission and distribution capacity value. Solar generation also pre-cools distribution system infrastructure by appearing on the system in advance of peak. This provides additional value. Solar generation stops when the sun sets and when the system is running on intermediate and baseload generation. As a result, solar generation does not displace baseload generation that must generally run many hours a day in order to achieve optimal efficiency. Finally, solar generation serves as an excellent complement to other technologies appearing at the distribution edge of the utility system, including storage (both stationary storage and electric vehicles) and demand response.

Q. Should solar generation be treated differently from other demand-side resources?

A. There is no basis to impose charges on solar generation for having the same effect on customer use as other demand side resources, at least up to the point that the solar customer is exporting energy to the grid. There is strong reason to believe that the value that solar provides to the utility and its customers justifies a credit for the solar customer, the value of which would be calculated by a comprehensive VOS analysis.

Q. What is the financial impact of SPS-1 on residential customers?

A. To calculate the financial impact of SPS-1 on residential customers, my analysis used assumptions and data for a typical, large residential customer with a 5.0 kW solar system. The residential solar customer has two options from which to choose: the new R-20 rate with the SPS-1 tariff or TOU-RD-1. The impact of both are shown in Table 1, below.

GPC Residential Solar Analysis Summary
Large Residential Customer (5.0 kW Solar Array), Rate R-20

	Annual Usage	Annual Elec Bill	Benefit of Solar PV System	Benefit Reduction Imposed by SPS	Solar Tax
	(kWh)	($)	($/yr)	($)	(%)
Rate R-20 (no solar)	22,039	$2,799			
Rate R-20 w/ Solar	15,289	$1,958	$842	--	--
Rate R-20 w/ Solar+ Proposed SPS	15,289	$2,393	$406	$435	**51.7%**
TOU-RD w/ Solar	15,288	$2,335	$464	$377	**44.8%**

Notes:

1. R-20, SPS and TOU-RD tariffs as proposed in 2013 GPC Rate Case, Docket No. 36989.
2. Residential Load shape used was provided by GPC in response to a Staff Data request.
   The 12 Mo. period OCT 2010 through SEP 2011 was used without explanation.
3. Solar production load shape obtained from a **5.0 kW** residential array in use during the period
   OCT 2012 to SEP 2013 using NREL production of 1350 kWh/kW for Atlanta.
4. The analysis above does not account for any compensation for energy sold to GPC
   under RNR tariff or other contracts (it assumes the PV array offsets consumption behind the meter).
5. Solar Tax is the reduction in economic benefits of solar generation proposed by GPC

in the 2013 Rate Case (Docket No. 36989).

6. "Rate R-20 w/ Solar" scenario above represents the Solar baseline to calculate Solar Tax.

Under SPS-1, the solar customer's bill will be increased by $435.00 annually over their anticipated bill under R-20 with solar deployed and generating. This is a 51.7% reduction in the savings they would have achieved under R-20. A customer on TOU-RD-1 will pay $377.00 more per year than under R-20 with solar generating, a 44.8% reduction in benefits relating to deployment of solar. These increased charges are punitive and unjustified by the evidence. I refer to these percentages as the equivalent of a solar tax.

Q. What is the impact on small/medium business customers?

A. To calculate the financial impact of SPS-1 on commercial customers, my analysis used assumptions and data for a typical, small TOU-MB business with a 30 kW solar system. When the TOU-MB commercial customer becomes a commercial solar customer, the PLM tariff applies. The impact of the transition from TOU-MB to PLM is shown in Table 2, below.

GPC Medium Business Customer Solar Analysis Summary

Medium Business Customer (30 kW Solar Array)

	Annual Usage	Annual Elec Bill	Benefit of Solar PV System	Benefit Reduction Imposed by SPS	Solar Tax
	(kWh)	($)	($)	($)	(%)
Rate PLM (no solar)	473,000	$50,035			
Rate TOU-MB (no solar)	473,000	$47,696			
Rate PLM w/ Solar	432,499	$47,989	$2,046	--	--
Rate TOU-MB with Solar	432,499	$43,092	$4,604	$2,558	**55.6%**

Notes:

1. PLM-9 and TOU-MB-5 rates as proposed in 2013 GPC Rate Case, Docket No. 36989.
2. Sales Tax rate used above is 7.0%.
3. Solar production load shape obtained from PV Watts for an installation in Atlanta. using NREL production of 1350 kWh/kW for Atlanta.
4. The analysis above does not account for any compensation for energy sold to GPC under RNR tariff or other contracts.

Under PLM, the commercial solar customer's bill will be increased by $2,558.00 annually over their anticipated bill under TOU-MB with solar deployed and generating. This is a 55.6% reduction in the savings they would have been achieved under TOU-MB with solar deployed. These increased charges are punitive and unjustified by the evidence. Again, this is a significant solar tax.

Q. Will DSG deployment anticipated over the next two rate case cycles present any significant issues of revenue recovery shortfall for the Company?

A. No, the amount of DSG deployed over the next two (2) rate cases will still be very small, particularly compared to the impact of energy efficiency measures implemented. I believe that the growth in deployment of DSG can be accurately projected in load forecasts. If the Company can truly substantiate an amount of capacity costs increased as a result, they would be reflected in VOS calculations.

BEST PRACTICES TO ASSESS COSTS AND BENEFITS OF DISTRIBUTED SOLAR GENERATION

Q. Has the Company calculated VOS?

A. The Company claims to have determined the true VOS in its ASI program.[2] However, the Company did not share its valuation in the IRP Docket, and it is not publicly available.[3] This lack of transparency makes it difficult to determine how the Company quantified VOS, and the factors

[2] Docket 36498, T. 2132, 2145-46.

[3] Docket 36498, T. 2233.

it considered.[4] I cannot find a publicly available document that describes how the solar avoided cost is calculated by the Company. As a result, the Commission and stakeholders have no way of knowing how the Company valued solar energy in ASI.

Q. How should the Company have assessed the costs and benefits of DSG?

A. The Interstate Renewable Energy Council ("IREC") recently published a white paper entitled "A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation," ("Regulator's Guidebook") that I co-authored along with Jason Keyes of the law firm of Keyes, Fox & Wiedman, laying out in some detail the best practices and methodologies for assessing the benefits and costs of distributed solar generation. With slight modification to account for conditions in Georgia, I offer that guidance to the Commission and the Company. The Regulator's Guidebook is attached to this testimony as Exhibit KRR-3.

Q. How does the guidance in the Regulator's Guidebook compare to the Company's proposals in this

[4] Docket 36498, T. 1167.

docket?

A. The Company's approach in this docket differs substantially from the best practices guidance offered in the Regulator's Guidebook. As noted, SPS-1 and its correlated TOU tariffs revisions are not based on a cost of service study or measured electricity data from DSG systems. The Company appears to have evaluated the costs or benefits of DSG based primarily on the energy value of solar generation. The Regulator's Guidebook provides comprehensive coverage of costs and benefits, and it proposes several methodologies that can be used to assess them.

Q. How does the guidance in the Regulator's Guidebook compare with the assessment of costs and benefits of distributed solar conducted at Austin Energy?

A. The best practices guidance reflected in the Regulator's Guidebook is substantially similar to that used at Austin Energy. The Regulator's Guidebook cites the Austin Energy approach frequently.

Q. How does the guidance in the Regulator's Guidebook compare to the approach used by the Company in

establishing its ASI solar rate?

A. In the IRP Docket, the Company stated that its ASI rate was based on the Austin Energy approach. I have not seen evidence from the Company that confirms this. I did note in my testimony in the IRP Docket that a value of \$0.13/kWh was similar to the \$0.128/kWh value calculated by Austin Energy. However, the mere similarity of rates alone does not mean that the Company applied Austin Energy's VOS methodology.

Q. Can you provide a summary of the best practices guidance for assessing solar value?

A. We provided a condensed summary of the Regulator's Guidebook at the end of the white paper, labeled as a "mini-guidebook." That summary advises the questions that should be asked at the start of any VOS study, the data sets required, and the benefits and costs that should be measured and how they should be measured.

PURPA AND SPS-1

Q. What is PURPA and which federal agency interprets it?

A. PURPA refers to the Public Utility Regulatory Policies Act of 1978. The Federal Energy Regulatory

Commission ("FERC") is the primary federal agency that interprets and implements PURPA.

Q. What does PURPA have to do with the rates and charges proposed for solar customers in this case?

A. Company witness, Mr. Roberts, stated one goal of SPS-1 and correlated TOU tariff charges was to ensure that solar customers are properly credited for their generation. FERC's rules on avoided cost calculations are therefore relevant and material in considering the Company's use of avoided costs as an apparent justification for solar rates and charges.

Q. Did the Company submit an avoided cost calculation or a cost of service study to substantiate its proposed solar rates and charges?

A. The Company conducted no cost of service study to support SPS-1. The Company's only attempt at an avoided cost calculation for DSG is its calculation of so-called "Expected Savings" derived from the Company's hourly marginal energy costs and solar production values of an unknown origin. The Company stopped far short of calculating a full avoided cost for DSG. Otherwise, I found no evidence of an avoided cost calculation.

Q. What is your recommendation regarding a solar avoided cost?

A. I recommend that the Commission, in a public proceeding, set a VOS calculation at full avoided cost rates for solar generation which (1) are just and reasonable to the Company's ratepayers, (2) are in the public interest, and (3) do not discriminate against small solar power producers. I believe that this is what the Commission ordered the Company to do in the IRP proceeding.[5]

Q. How does your recommendation impact the Company's SPS-1 tariff proposal?

A. The Company is implicitly attempting to establish a solar avoided cost rate in this docket, as it appears in the calculations used to establish the SPS-1 and correlated TOU rates. But, there was no the public process, evidence, and evaluation required for sound ratemaking. Given the Commission's direction to the Company in the IRP

[5] Correction to Order, Docket No. 36498, p. 3 ("ORDERED FUTHER, that no bids for the Utility Scale solar shall be accepted which exceed Georgia Power's projected levelized avoided cost for the term of the PPA. Such avoided cost will be established and announced by Georgia Power Company, and approved by the Commission prior to beginning the RFP process.").

proceeding, the Company should not be permitted to peremptorily use this docket and its proposed SPS-1 tariff to posture its required IRP cost filing in advance. The Commission should deny the Company's request to implement SPS-1 in this docket and defer its consideration to the solar avoided cost proceeding anticipated in the IRP Order.

VALUE OF SOLAR ANALYSIS

Q. What is VOS analysis?

A. I testified on VOS analysis in the IRP Docket earlier this year. VOS analysis is, in essence, a full avoided cost approach with a long term valuation perspective. Most VOS studies share a common general approach and general structure. VOS analysis identifies and characterizes the value attributes of DSG in two steps: benefits and costs are identified and grouped; then the benefits and costs are quantified. Valuation results vary depending on specific methodologies, local energy markets, and other factors. A growing body of VOS research demonstrates that distributed solar energy has value that exceeds electric utility and ratepayer costs. The portions of my testimony in the IRP Docket pertinent to VOS are incorporated herein and attached hereto as Exhibit KKR-4.

Q. Generally, what are the benefits and costs considered in VOS analysis?

A. The benefits and costs studied in a VOS analysis are those that accrue to the utility and its ratepayers as a result of meeting demand for electricity using a distributed solar electric facility rather than the incumbent electric utility's current and planned system resources. These benefits and costs are created when the solar facility generates energy over its entire useful life. They are quantified using system average and location specific values associated with displaced utility "system" energy.

Q. What categories of benefits and costs are examined in VOS analysis?

A. In my testimony in the IRP Docket, I identified the following categories of benefits and costs studied in VOS analysis:

Energy
Capacity
Grid support
Customer benefits
Financial and security benefits
Environmental benefits
Social benefits

I defined each category in my IRP testimony. (Exhibit KKR-4).

Q. Can you update the Commission on VOS research?

A. Yes, a representative list of the studies is described in greater detail in attached Exhibit KRR-5, which is a recent report from the Rocky Mountain Institute's ("RMI") eLab Project entitled: "A Review of Solar PV Benefit and Cost Studies." In my IRP Docket testimony, I also cited the Perez study: "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania" (Exhibit KKR-6) which modeled the value of a 15% peak load penetration of DSG at seven locations in the region, addressing values for market price reduction, environmental value, transmission and distribution capacity value, fuel price hedge value and generation capacity value. The Perez VOS study is a good example of a comprehensive VOS study and the resulting VOS determination.

Q. What conclusions can you draw from the developing body of VOS research?

A. The RMI meta-analysis of and my own VOS research confirm findings of substantial value in each of the categories identified above. The published studies differ in important respects, and they cannot be simply averaged or summed. However, I reach the following conclusions:

a. Studies with more comprehensive analysis discern greater value in a greater number of categories;

b. Studies that calculated the levelized value of a stream of benefits and costs associated with solar electric generation over the useful life of the facilities reveal substantially greater value than those using annualized estimates of value. "Snapshot" analyses are highly influenced by current rate, fuel price, and other parameters;

c. Studies that internalize planning assumptions that are biased against distributed resource scale and other characteristics systematically underrate the value of distributed solar;

d. Studies that quantify risks, such as fuel price volatility and environmental regulation, find greater value in DSG, which has little or no risk in these categories.

Non-utility solar electric generation mitigates significant risk associated with utility-owned facilities, and substantially reduces the net investment cost for generation for all ratepayers. In sum, sound valuation is fundamental to efficient solar deployment. Comprehensive analysis of the benefits and costs of DSG often reveals net value that substantially exceeds the cost to the utility and its ratepayers.

Q. From the VOS research, can you conclude that DSG facilities in Georgia confer net benefits to the Company and its ratepayers?

A. Yes. Though the VOS studies were not based on Georgia specific data, enough research is complete in the United States that general application is reasonable. Given the diversity of the data sets in the completed VOS studies and the relatively high importance of energy costs in the estimation, the value delivered by DSG to the Company and its ratepayers results in comparable net benefits and downward pressure on rates. This evidence warrants conducting the VOS analysis that I propose.

VOS AND TRADITIONAL AVOIDED COST METHODOLOGIES

Q. How is VOS analysis relevant to setting "full" avoided cost rates?

A. As an avoided cost calculation embracing the full range of costs avoided by DSG over the life of the solar generation system, VOS better approximates the "full avoided costs" associated with DSG. VOS offers improved market pricing signals over traditional avoided cost calculations, including calculations made under the traditional "peaker" methodology.

Q. Why are traditional avoided cost calculations inadequate to capture full avoided costs attributable to DSG?

A. Traditional avoided cost calculations evolved when grid generation was centralized. The calculations did not recognize all of the benefits and costs, such as the full amount of transmission, distribution, and line loss costs avoided by distributed generation. The calculations do not adequately assess the loss of important risks, such as fuel price volatility and water supply distribution. The spectrum of viable generation resources has broadened and the analytical tools to understand them have improved since the traditional avoided cost methodologies were developed. We now understand that all generation resources do not bear the same costs and risks. Ratemaking should reflect that reality.

Q. Do any other factors limit the range of benefits and costs reviewed under traditional avoided costs methodologies?

A. Yes. Avoided cost estimation under PURPA (as implemented by FERC) is jurisdictionally limited to wholesale power sales and related transactions. PURPA was not intended or designed to fully address all of the issues associated with distributed resources that must be reviewed to determine the full extent of costs avoided by a utility when these resources are installed. Only state commissions can ensure that these benefits and costs are captured properly through state-level implementation.

Q. Does the Commission have authority to require the development and approval of a full avoided cost for DSG?

A. Yes. The Commission has considerable authority under PURPA and FERC regulations to require quantification of the full avoided cost for DSG. FERC’s regulations allow the states to consider numerous factors in determining full avoided costs,[6] including:

- Reduced line losses;
- Ability to install smaller increments of capacity with shorter lead times;
- Ability to avoid or defer transmission and distribution costs;
- Value of QF capacity and energy;
- Ability to dispatch QF output; the expected or demonstrated reliability of the output; and the usefulness of QF production during system emergencies;
- Environmental benefits and renewable attributes of QF power; and
- Duration and enforceability of QF contracts.

Q. Can you elaborate on the fuel price risk?

A. Yes. DSG is very different from resources that depend on long-term availability of affordable fuel. DSG has no fuel cost, now or ever. The risk of natural gas price volatility is either ignored or undervalued in traditional avoided cost calculations. Instead, fuel costs are passed to customers through annual fuel cost recovery riders. Undervaluing fuel volatility risk makes it seem

[6] The authorization for consideration of these factors, respectively, can be found at: 18 C.F.R. § 292.304(e) (4); 18 C.F.R. § 292.304(e) (2)(vii); 18 C.F.R. § 292.304(e) (3); 18 C.F.R. § 292.304(e) (2)(vi); 18 C.F.R. § 292.304(e) (2)(i); 18 C.F.R. § 292.304(e) (2)(ii); 18 C.F.R. § 292.304(e) (2)(v); see, e.g., Southern California Edison , 133 FERC ¶ 61,059 at P 31 ("[I]f the environmental costs 'are real costs that would be incurred by utilities,' then they 'may be accounted for in a determination of avoided cost rates.'"), rehearing denied, 134 FERC ¶ 61,044; 18 C.F.R. § 292.304(e) (2)(iii).

like DSG avoids less cost than it actually does.

Q. Can you elaborate on the water cooling and environmental regulation risks?

A. Yes. There is a real risk that carbon emission regulations will increase the Company's costs associated with its fossil fuel generation fleet. DSG avoids these potential federal regulatory carbon costs. DSG has no exposure to water scarcity over its entire useful life, giving it significant value on a stand-alone basis and as part of a generation portfolio. Development of domestic shale gas faces regulatory uncertainty (and a risk of increased costs) in a carbon-constrained future where impacts associated with development are still uncertain and under examination. DSG avoids these potential costs.

Q. How should VOS relate to the price paid by an electric utility when it purchases or credits solar generated electricity?

A. VOS should set a benchmark for the price an electric utility pays or credits for third-party DSG. VOS analysis quantifies the value equal to what it would cost either the utility or a third party to provide solar energy to the point where the energy does its work. It sets an "indifference price" just as avoided cost calculations are intended.

Q. Do the Company's SPS-1 and correlated TOU tariffs set a VOS?

A. From a review of the filings in this case, there is no evidence that the calculations underlying the proposed SPS-1 and the correlated TOU tariff rates fully quantify the benefits described above, or even approximate the benefits captured by the calculations that the Company might have performed in setting its ASI rate of $0.13/kWh.

Q. What does this mean in practical terms?

A. In practical terms, the Company's proposed SPS-1 and correlated TOU tariffs are not based on market value or measurement of electricity flow. As a result, they impose rates on solar customers that are not just and reasonable. Systematic undervaluation of DSG denies ratepayers the benefit of procuring this resource at a cost that will yield substantially greater benefits, including downward pressure on rates over time. Furthermore, undervaluing solar electric generation discriminates against small power producers who would otherwise offer this resource into the mix at rates that are just and reasonable to ratepayers. Finally, the systematic undervaluation of solar electric generation is not in the public interest because it promotes suboptimal and economically inefficient investment levels in the solar resource, and by definition leads to over-investment in second-best resource choices and riskier generation alternatives.

RECOMMENDATIONS

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission:

a. Direct the Company to withdraw its SPS-1 tariff and all correlated TOU tariff changes relating to customers who deploy solar generation;

b. Direct the Company to cease imposing charges, requirements, or conditions on solar customers pending final action by the Commission in a VOS docket;

c. Convene an open, transparent stakeholder process to study and develop a comprehensive VOS solar study applying best practices as set forth in the Interstate Renewable Energy Council's "Regulator's Guidebook" relating to assessment of benefits and costs of distributed solar generation;

d. Retain an independent third party consultant, selected through the stakeholder process, to provide technical assistance in conducting the VOS study and developing an appropriate VOS calculation and rate; and

e. Direct the Company to share any and all data necessary with the stakeholder group and the third party consultant in order to fully and comprehensively assess VOS in the Company’s service territory.

Q. Does this conclude your testimony?

A. Yes.