STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators	**DOCKET NO. 2019-182-E**

REBUTTAL TESTIMONY

R. THOMAS BEACH

ON BEHALF OF

THE SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTHERN ALLIANCE FOR CLEAN ENERGY, UPSTATE FOREVER, VOTE SOLAR, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, and THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

October 29, 2020

TABLE OF CONTENTS

I. INTRODUCTION

Q: PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A: Yes, on October 8, 2020, I submitted direct testimony on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, the Solar Energy Industries Association, and the North Carolina Sustainable Energy Association. My experience and qualifications are presented in my CV, which is Exhibit RTB-1 to my direct testimony.

II. EXECUTIVE SUMMARY

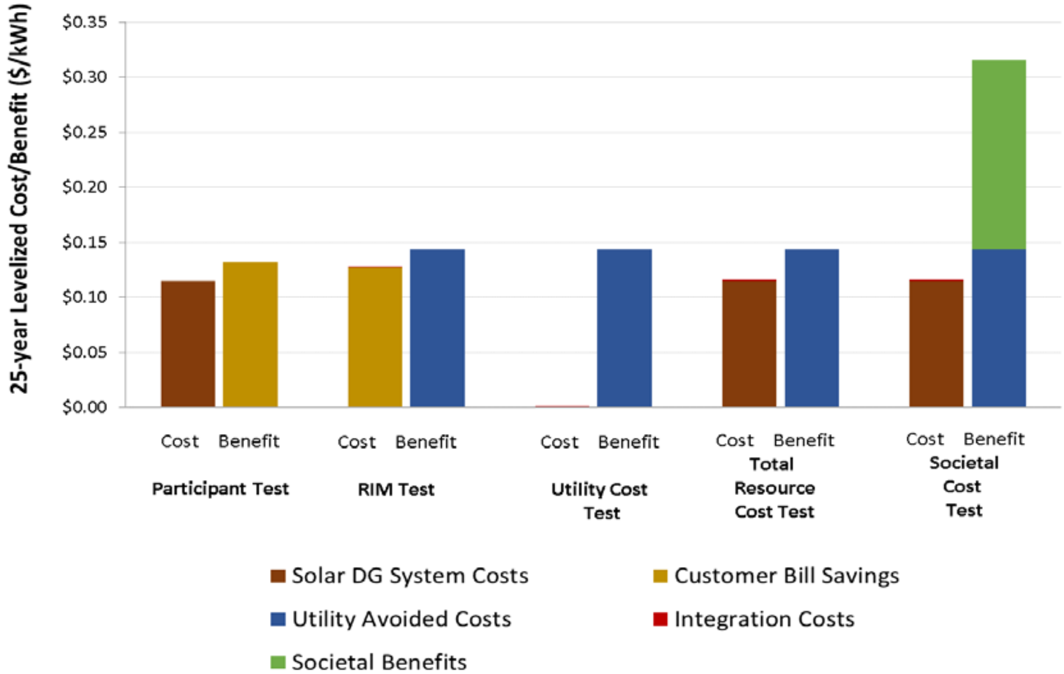
Q: PLEASE PRESENT A BRIEF SUMMARY OF YOUR REBUTTAL.

A: This rebuttal testimony focuses first on the benefit and cost numbers for residential solar presented in the testimony of Dominion Energy South Carolina (DESC or Dominion). DESC fails to consider and quantify all of the benefits and costs of DERs that the Commission adopted in Order No. 2015-194 and that Act 62 states should be considered in evaluating the upcoming Solar Choice tariffs. In some cases (such as avoided energy costs), the utility does not analyze the benefits over the full 25-year economic life of distributed solar resources. With respect to other quantifiable benefits (such as avoided capacity costs for transmission and distribution, avoided fuel hedging costs, and avoided costs to reduce carbon emissions), the utility testimony is silent.

In response, this rebuttal quantifies the full slate of the benefits and costs of distributed solar on the DESC system, revising many of DESC Witness Margot

Everett's numbers and providing several benefits that DESC does not recognize. I then apply the full set of Standard Practice Manual (SPM) cost-effectiveness tests to residential solar on the DESC system. The following **Figure ES-1** shows the results:

Figure ES-1: *Summary of SPM Test Results*



At this time, residential solar on the DESC system appears to pass all of the SPM cost-effectiveness tests. As a result, there is not presently a cost shift from solar customers to non-participating ratepayers, and distributed solar is a cost-effective resource for DESC ratepayers. There is also a small net benefit for customers who install solar, indicating that the market should continue to grow, albeit slowly, under the present net metering tariffs. Finally, there are significant, quantifiable societal benefits from distributed solar, including public health benefits from reduced air pollution and from mitigating the damages from carbon emissions.

I recommend that a similar analysis should be applied to the Solar Choice tariffs that DESC and the other South Carolina utilities may propose in future utility-specific proceedings pursuant to Act 62.

Finally, my testimony responds briefly to the opening testimony of the Office of Regulatory Staff (ORA) on a cost-of-service issue for the Duke Energy utilities and on the possible impacts of Solar Choice tariffs on low-income customers.

III. RESPONSE TO DOMINION ENERGY SOUTH CAROLINA

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH DESC'S TESTIMONY ON THE METHODS TO BE USED TO DEVELOP SOLAR CHOICE TARIFFS PURSUANT TO ACT 62.

A. My direct testimony discusses the five key attributes of a benefit/cost methodology for net-metered distributed energy resources (DERs) that is consistent with Act 62. Two of these attributes are that the method should:

- consider a comprehensive list of benefits and costs and,
- use a long-term, life-cycle analysis.

As discussed below, the testimony of DESC witness Everett does not consider and quantify all of the benefits and costs of DERs and does not analyze them over the full 25-year economic life of the distributed solar resources that will be developed under the Solar Choice tariffs. This rebuttal presents my own calculation of the benefits and costs of distributed solar today on the DESC system; I revise many of DESC Witness Everett's numbers and supply several benefits that DESC does not recognize.

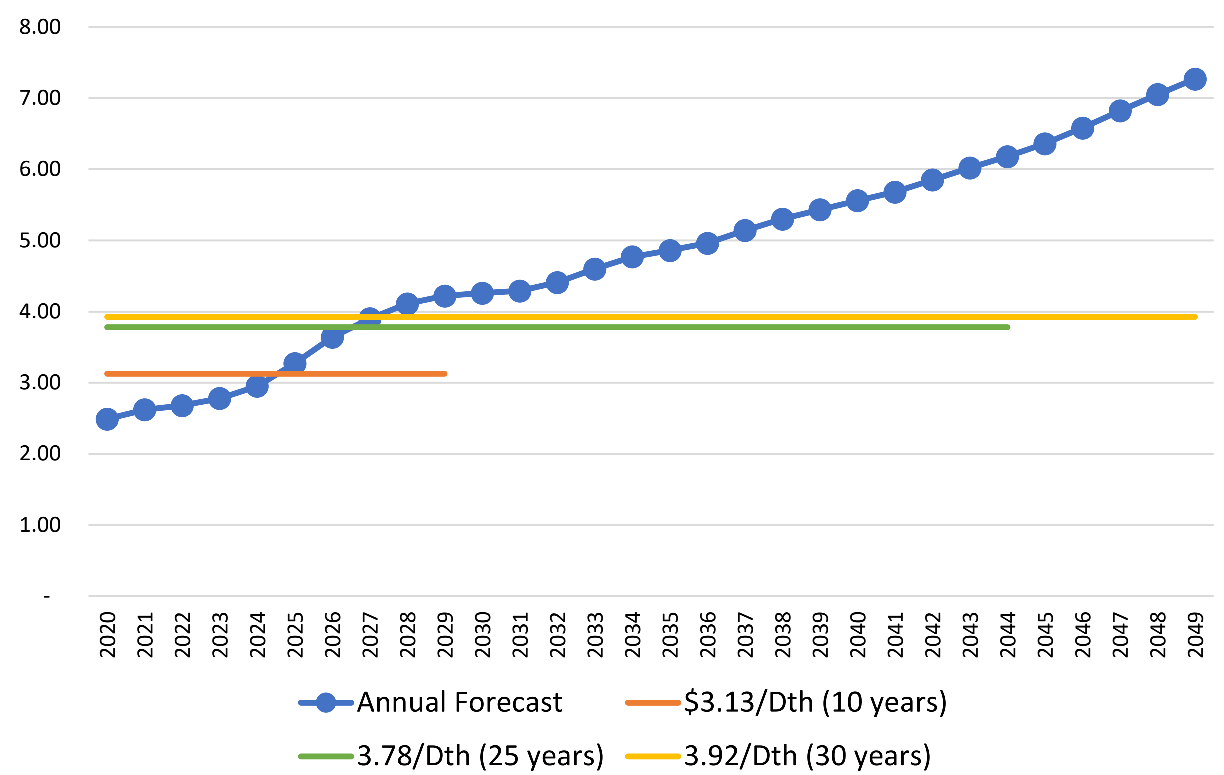
A. Avoided Cost of Energy

Q: WHAT ARE THE AVOIDED ENERGY BENEFITS OF A SOLAR PHOTOVOLTAIC (PV) PROJECT?

A: New solar generation will displace the marginal source of electric energy on the Dominion system. To calculate avoided energy costs, DESC Witness Everett's testimony appears to use Dominion's 10-year levelized energy prices by time-of-use (TOU) period that are included in its standard offer Power Purchase Agreement tariff (PR-1). These avoided energy costs should be extended to the

25-year economic life of a solar system. To estimate avoided energy costs over a 25-year horizon, I started with DESC's 10-year levelized PR-1 energy prices, then escalated these ten-year levelized energy prices based on the increase in levelized natural gas prices over a 25-year forecast period versus a 10-year period. With gas-fired generation expected to be the predominant marginal resource on the DESC system in the future, it is reasonable to expect that marginal energy costs will escalate with natural gas costs over time. For this step, I used the Energy Information Administration's (EIA) *2020 Annual Energy Outlook* (AEO) forecast of natural gas prices at the Henry Hub, Louisiana. **Figure 1** below shows that gas price forecast, as well as the levelized prices over various terms. The 25-year levelized price represents a 21% percent increase over the 10-year levelized price, assuming an 8.5% discount rate corresponding to DESC's weighted average cost of capital.

Figure 1: *2020 AEO Forecast Natural Gas Price*



Applying these increases in levelized natural gas prices to Schedule PR-1 prices results in the avoided energy rates shown in **Table 2** below. **Table 1** shows the Schedule PR-1 energy prices from which I started. These are the avoided energy benefits that a solar project can provide, expressed on a TOU basis.

Table 1: Schedule PR-1 Energy Credits for a 10-year Period ($/kWh)

TOU Period	June-September	October-May
On Peak	$0.03105	0.03252
Off Peak	$0.02751	0.02893

Table 2: Escalated Energy Credits for a 25-year Period ($/kWh)

TOU Period	June-September	October-May
On Peak	$0.03754	0.03931
Off Peak	$0.03326	0.03487

Q: HAVE YOU ESTIMATED AN AVERAGE 25-YEAR LEVELIZED PRICE FOR THE AVOIDED ENERGY BENEFITS OF SOLAR PV?

A: Yes. Based on DESC's TOU periods[1] and estimated annual solar output by TOU period,[2] I computed the following weighted average prices for a typical solar PV project:

Table 3: Annual Average Solar PV Energy Credits $/kWh)

Term	Avoided Energy Benefit
10 years (2020-2029)	0.03056
25 years (2020-2044)	0.03694

[1] The peak period for DESC is Hour Ending (HE) 11-22 in May to October, and HE 7-13 & 18-22 in November to April.

[2] I estimate solar output using the National Renewable Energy Lab's PVWATTS tool. I assumed the default PV Watts settings for a rooftop PV system in Charleston, SC. These include a 4.0 kW-DC system size, fixed 20-degree tilt, south-facing orientation, and a 1.2 DC to AC inverter loading ratio.

Q: DO YOU BELIEVE THESE ARE REASONABLE AVOIDED ENERGY BENEFITS?

A: Yes. Dividing the solar weighted average energy price (0.0306 $/kWh over ten years), net of variable O&M, by the 2020 AEO forecast price of natural gas ($3.13 per Dth), adjusted for transportation, results in a market heat rate of about 6,500 Btu/kWh.[3] This is not an unreasonable assumption if solar displaces conventional natural gas-fired generation from an efficient Combined Cycle Gas Turbine (CCGT) in most hours. This relatively low market heat rate may reflect some hours when non-gas resources with lower variable costs than a CCGT are on the margin.

B. Avoided Generation Capacity

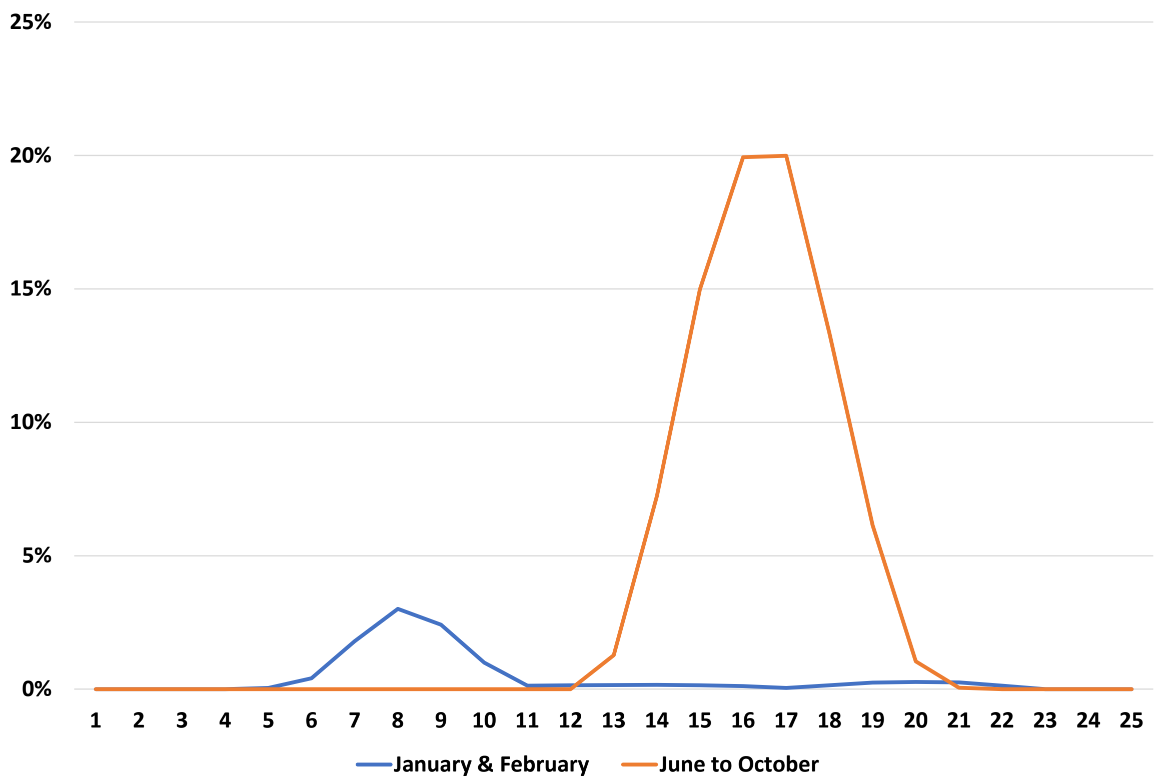
Q: WHAT ISSUES HAVE YOU IDENTIFIED WITH DESC'S STATED AVOIDED GENERATION CAPACITY COSTS FOR A SOLAR PV PROJECT?

A: The most significant issue is the capacity contribution of solar to avoiding DESC's need for generation capacity. To estimate solar's capacity contribution in the recent past, I looked at five years of hourly DESC loads, from 2015 to 2019, as reported to FERC in Form 714, and developed a Peak Capacity Allocation Factor (PCAF) for each hour of the year, based on the extent to which hourly load exceeds 90% of the annual peak hour's load. Due to the potential for both summer and winter peaks, it is important to look at a five-year period to capture the relative frequency of these seasonal peaks. This results in probability weights in each hour and month of the year that are concentrated on afternoon hours in summer months and on morning hours in January, as shown in **Figure**

[3] Assuming variable O&M equal to $0.00255 per kWh, from Table 2 of EIA's February 2020 report on capital cost benchmarks (at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf), and gas transportation cost of $1.20 per MMBtu, this calculation is ($30.60/MWh - $2.55/MWh) x 1000 / ($3.13/Dth + $1.20/Dth) = 6,472 Btu/kWh.

2 below. The smaller allocation of generation PCAFs to the winter reflects the shorter and less frequent utility peaks during winter cold snaps.

Figure 2: *Average 2015-2019 Generation PCAFs*



Applying a solar profile to the PCAF distribution results in a solar PV capacity contribution of 34%. Thus, I assume that 34% of a solar PV project's capacity may be assumed to contribute to meeting DESC's capacity needs in its peak load hours.

Q: WHAT ARE DESC'S AVOIDED GENERATION CAPACITY COSTS?

A: The approach that I used to calculate the DESC's long-run avoided capacity costs for generation is based on the cost of a new combustion turbine (CT), as the marginal source of capacity. Various sources exist to estimate this cost. DESC's 2020 Integrated Resource Plan (IRP) indicates that the capital cost of a new CT is \$918 per kW.[4] Alternatively, the EIA's report on capacity cost benchmarks,

[4] See the table at page 39 of the DESC 2020 IRP.

referenced in footnote 3 above, indicates a CT capital cost in the range of $713 per kW (for 237 MW from a 1 x GE 7FA) to $1,150 per kW (for 105 MW from 2 x LM6000 units), with an average of $944 per kW.

In the calculation below, I have used the DESC IRP CT capital cost of $918 per kW; this CT unit is in all of the utility's resource plan scenarios.[5] The following **Table 4** shows that, after using a real economic carrying charge (RECC) factor to annualize the capital cost, adding a 14% reserve margin, applying the 34% capacity contribution for solar PV, and dividing by expected annual solar output, the avoided generation capacity cost for a solar PV project is $0.01351 per kWh. This can be compared to the current Schedule PR-1 capacity credit of $0.00379 per kWh. However, when the current credit is adjusted upward for my recommended 34% solar capacity contribution, rather than the 11% solar capacity contribution adopted in amended QF Order No. 2019-847, the result is a similar avoided cost capacity value of about $0.012 per kWh.

Table 4: Avoided Generation Capacity Costs

line	**Component**	**Value**	***Notes***
A	CT Cost ($ per kW)	918	*Based on DESC IRP*
B	RECC Annualization Factor	7.4%	*Calculated RECC*
C	Annual Cost of New Capacity ($/kW-year)	67.93	*A x B*
D	Plus 14% Reserve Margin ($/kW-year)	77.44	*IRP Summer PRM*
E	Solar Capacity Contribution	34%	*PCAF Analysis*
F	Avoided Generation Capacity ($/kW-year)	23.10	*D x E*
G	Solar Annual Output (kWh per kW)	1,709	*PVWATTS Charleston*
H	Avoided Generation Capacity ($/kWh)	0.01351	*F / G*

C. Avoided Energy and Capacity Losses

Q: DO YOU AGREE WITH DESC WITNESS EVERETT THAT THE POWER EXPORTED FROM DISTRIBUTED SOLAR FACILITIES DOES NOT AVOID DISTRIBUTION LINE LOSSES?[6]

[5] DESC 2020 IRP, at pp. 40-41.
[6] See DESC Testimony (Everett), at pp. 16-17.

A: No, I do not. Assuming that the penetration of distributed solar is low, as it is in South Carolina today, the power exported from a small customer-owned solar system on the distribution system will be consumed by the solar customer's immediate neighbors. These exports will displace system power that otherwise would need to be delivered to the neighbors from remote utility-scale generation over the utility's entire upstream transmission and distribution facilities. The avoided system power for the neighbors would have been transmitted and distributed over virtually the same distance as the power that the solar customer avoids by serving its own load behind the meter. As a result, the avoided line losses associated with exports from distributed solar will be very similar to the avoided losses for the power consumed behind the solar customer's meter. In essence, because the exports from distributed solar move such a short distance over the distribution system before they are consumed by the neighbors, the avoided line losses will not be significantly different than the avoided losses from power consumed behind the meter.[7]

Q: PLEASE DISCUSS THE ENERGY AND CAPACITY LINE LOSSES THAT DISTRIBUTED SOLAR WILL AVOID.

A: The avoided energy and capacity costs calculated above are at the generation level. A solar PV project located behind a customer's meter avoids marginal line losses on both the DESC transmission and distribution systems for its entire output. Thus, based on DESC's marginal energy and capacity losses, I have calculated the following avoided line losses.[8]

[7] This situation will change only if the penetration of distributed solar grows to the point that distributed solar output exceeds the midday minimum load on many distribution circuits, such that solar exports backfeed up these circuits to the nearest distribution substation. This issue has become significant only in a market such as Hawaii, where solar penetration has reached about 20% of residential customers. This is far higher than the current residential solar penetration in South Carolina.

[8] Provided in response to Question 16a of the first data request of Vote Solar, *et al*. to DESC.

Table 5: Avoided Line Losses

Component	%	$/kWh
Avoided Energy Losses	8%	0.00204
Avoided Capacity Losses	15%	0.00305
Total Avoided Losses		0.00493

D. Avoided transmission and distribution capacity

Q: DESC WITNESS EVERETT DOES NOT ADDRESS THE ISSUE OF AVOIDED TRANSMISSION AND DISTRIBUTION (T&D) CAPACITY COSTS ON THE DESC SYSTEM. DOES A SOLAR PV PROJECT AVOID T&D CAPACITY COSTS?

A: Yes. Because a solar PV project's output will serve much of a customer's on-site load, without ever flowing onto the grid, DESC may expect to see reduced loads on its T&D system. The remaining power that is be exported to the grid is likely to be substantially consumed by neighboring distribution loads, thus unloading the upstream DESC transmission and distribution systems.

Q: HOW DID YOU DETERMINE THE CONTRIBUTION OF SOLAR OUTPUT TO AVOIDED TRANSMISSION AND DISTRIBUTION SYSTEM CAPACITY COSTS?

A: Solar avoids transmission and distribution (T&D) investments by reducing peak loads on the DESC T&D system. Similar to my Peak Capacity Allocation Factor (PCAF) analysis for generation capacity contributions from solar PV, I performed PCAF analyses based on transmission system and distribution system hourly loads provided by DESC. This load data includes hourly loads at each DESC transmission and distribution substation.[9] Compared to my PCAF analysis of the solar contribution to generation capacity (which was based on

[9] The inputs to the PCAF analyses I performed for transmission and distribution were, respectively, DESC's hourly transmission bank and distribution substation loads. I calculated a weighted average transmission PCAF by weighting the PCAF allocations for each transmission bank by its maximum load; similarly, the distribution PCAF allocation weighted the PCAF allocations for each distribution substation according to DESC-indicated capacity of each distribution substation.

system load data), the T&D PCAF analyses show similar, but modestly higher, solar capacity contributions of 43% for transmission and 36% for distribution.

To estimate the marginal cost of T&D capacity, I have used the well-accepted National Economic Research Associates (NERA) regression method. This approach is used by many utilities to determine their marginal transmission and distribution capacity costs that vary with changes in load. The NERA regression model fits incremental T&D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T&D investments associated with changes in peak demand.[10] To capture long-run marginal costs, the NERA methodology typically uses at least 15 years of data on T&D investments and peak transmission system loads. This data is historical data reported in FERC Form 1, plus a current forecast of future investments and expected load growth if available. I have utilized NERA regressions based on DESC's historical peak load growth and transmission and distribution investments over the period from 2009 to 2025, using DESC's FERC Form 1 data for the historical portion of this period through 2019, as well as a six-year forecast of T&D investments and load growth (2020-2025). I add loaders for the operations and maintenance (O&M) and administration and general (A&G) costs associated with these investments in T&D rate base. These loaders are based on Form 1 data on T&D O&M and A&G costs as percentages of rate base investments.

The testimony of Brian Horii for the Office of Regulatory Staff (ORS) observes that these regressions based on coincident peak demand overstate marginal T&D costs, because the sum of the noncoincident peak loads on the elements of the T&D system that drive investments are higher than the coincident system peak loads used in the denominator of marginal T&D costs.[11] I agree that

[10] It is important to keep in mind that peak load growth is a proxy for growth in T&D capacity. Some utilities – for example, Southern California Edison – track their T&D system capacity over time and use this data directly in the regression.
[11] See direct testimony of Brian Horii on behalf of the South Carolina Office of Regulatory Staff, at pages 29-30.

this observation has merit, particularly given that my PCAF analysis also looks at a range of hours with loads within 10% of the peak hour, and not just at the peak hour. Accordingly, I have included 27% and 23% downward adjustments to the avoided transmission and distribution capacity costs, respectively, to recognize that marginal T&D costs per unit of noncoincident peak loads on the T&D systems are lower than the marginal T&D costs per unit of coincident system peak loads. DESC's distribution load data indicates that the coincident system peak load is 23% lower than the sum of noncoincident peak distribution substation loads. Similarly, the coincident peak load on the transmission system is 27% lower than the sum of non-coincident transmission bank peak loads.

My analysis results in dollars per kW values for avoided T&D capacity, which I annualize using a RECC factor. I then multiply these annualized values by the PCAF-based solar contribution to avoiding T&D capacity. Finally, to express this avoided transmission cost on the basis of dollars per MWh of solar output, I divide by the expected annual output of distributed solar PV, in kWh per kW. The final step I perform is to assume these costs will increase with inflation and to levelize them over 25 years at an 8.5% discount rate. The following **Tables 6 and 7** show the results of my calculation of the DESC avoided T&D capacity costs.

Table 6: Avoided Transmission Capacity Costs

Line	**Component**	**Value**	***Notes***
A	Avoided Transmission Capacity ($/kW-year)	63.56	*NERA method*
B	Solar Capacity Contribution	42.5%	*PCAF method*
C	Solar Annual Output (kWh per kW)	1,709	*From PVWATTS*
D	Avoided Transmission Capacity ($/kWh)	0.01581	*A x B / C*
E	Adjusted for 25-year Levelized Value	0.01861	*D x 1.18*

Table 7: Avoided Distribution Capacity Costs

Line	**Component**	**Value**	***Notes***
A	Avoided Distribution Capacity ($/kW-year)	92.57	*NERA method*
B	Solar Capacity Contribution	35.6%	*PCAF method*
C	Solar Annual Output (kWh per kW)	1,709	*From PVWATTS*
D	Avoided Transmission Capacity ($/kWh)	0.01928	*A x B / C*
E	Adjusted for 25-year Levelized Value	0.02270	*D x 1.18*

The sum of these avoided transmission and distribution costs is $0.04131 per kWh.

E. Fuel Hedge Benefits

Q: DESC WITNESS EVERETT DOES NOT DISCUSS OR INCLUDE A FUEL HEDGE BENEFIT. SHOULD SUCH A BENEFIT BE INCLUDED?

A: Yes. Renewable generation, such as solar PV, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility and periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 3** below.

Renewable generation provides a long-term hedge against volatile fuel costs for the entire 25-year economic life of, for example, a solar unit. As discussed in my opening testimony, calculations of this component underestimate this benefit by focusing on the costs of existing utility hedging programs. These programs only reduce the volatility in short-term fuel and purchased power expenses for the next one to three years. In contrast, there are substantial financial costs to establish a long-term hedge equivalent to what renewable generation provides.

Figure 3: Henry Hub Natural Gas Market Prices

Q: HOW WOULD YOU CALCULATE THE FUEL HEDGE BENEFIT?

A: To calculate this benefit, I follow the methodology used in the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research.[12] This approach recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on a "pay as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar PV displaces.

I have performed this calculation for DESC, using my base gas cost forecast (the EIA *AEO 2020* forecast), U.S. Treasuries (at current yields) as the risk-free

[12] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

investments, and a marginal heat rate of 6,500 Btu per kWh. The result is a value of $0.033 per kWh as the 25-year levelized benefit of reducing fuel price uncertainty. Short-term hedge transactions do not capture this long-term fuel hedge value, given that short-run price volatility (i.e. in the next 12-months or next 3-5 years) is not the same as price volatility over a 25-year period. For example, highly liquid futures markets do not exist over a 25-year timeframe, because of the significant costs and risks involved. Instead, ratepayers bear these risks and costs over the life of a fossil-fueled resource whose fuel costs are volatile, because ratepayers ultimately “pay as you go” at the prevailing market price for fuel. Renewable generation provides a significant benefit to ratepayers by eliminating the risks of this volatility.

F. Avoided GHG Emission Benefits

Q: DESC WITNESS EVERETT DOES NOT INCLUDE A BENEFIT ASSOCIATED WITH AVOIDED COSTS TO REDUCE GREENHOUSE GAS (GHG) EMISSIONS. PLEASE COMMENT.

A: My opening testimony argues that the IRPs of the South Carolina utilities, including DESC, show that reducing future carbon emissions is a significant driver of those plans and that the utilities are planning and spending money today to reduce their carbon emissions.[13] Therefore, the benefit associated with reducing carbon emissions should not be assumed to be zero.

Q: HAVE YOU CALCULATED THIS BENEFIT?

A: Yes. DESC’s 2020 IRP assumes carbon costs of $25 per MT for compliance with future GHG regulations.[14] I assumed this cost increases with inflation at 2% per year. Using the conversion factor that burning an MMBtu of natural gas produces 117 pounds of carbon dioxide, DESC’s IRP assumption for GHG compliance costs is equivalent to approximately a $1.50 per MMBtu adder to the cost of natural gas. Assuming a 6,500 Btu/kWh marginal system heat rate, this

[13] See pages 26-29 of DESC’s 2020 IRP.
[14] DESC 2020 IRP, at p. 44.

component becomes \$0.00951 per kWh in 2020, or \$0.01124 per kWh on a 25-year levelized basis.

G. Summary of Benefits

Q: PLEASE SUMMARIZE THE AVOIDED COST BENEFITS FOR SOLAR PV PROJECTS ON THE DESC SYSTEM.

A: This summary is provided in **Table 8**, below.

Table 8: Summary of Avoided Cost Benefits

Avoided Cost Component	**Value** *(25-year levelized \$ per kWh)*
Energy	0.0383
Generation capacity	0.0135
Line losses	0.0049
Transmission capacity	0.0186
Distribution capacity	0.0227
Fuel Hedge	0.0335
GHG Compliance Costs	0.0112
Total	**0.1428**

H. Bill Savings

Q: HAVE YOU ANALYZED RESIDENTIAL CUSTOMER BILL SAVINGS ON THE DESC SYSTEM?

A: Yes. These savings are the primary benefit of solar for participating customers, and thus are used in the Participant Cost Test. Bill savings also are the lost revenues for the utility when a customer adopts solar, and thus are the principal cost in the RIM test.

I modeled residential bill savings for DESC's standard tiered rates for residential service. Assuming a residential customer with an annual load of 12,000 kWh per year, and a solar system sized to serve 75% of that load (i.e., solar output of 9,000 kWh per year), I estimate monthly pre-solar costs of about \$125 per month, dropping to monthly post-solar costs of \$41 per month, for bill savings of \$84 per month on the tiered rate. The portion of overall bill savings related to the portion of solar output that is exported to the grid should be the focus of a NEM cost-benefit analysis, given that customers have rights under federal law (PURPA) to serve their own load and Act 62 specifically states that the solar choice tariff should not penalize behind-the-meter use of customer-generation.

To determine a long-term levelized value for bill savings from exported power, I escalate the savings with inflation over a 25-year period, including the effect of solar degradation over time,[15] then levelize the savings at an 8.5% discount rate. These bill savings for exported power are summarized in the final line of the following **Table 9**, in terms of dollars per year, per month, and per kWh of solar exports.

Table 9: Dominion Residential Customer Solar Bill Savings on Tiered Rate

	$ / year	**$ / month**	**kWh**	**$ / kWh**
Pre-solar Bill	$1,503	$125	12,000	0.125
Post-solar Bill	$492	$41	3,000	0.164
Bill Savings – total	$1,011	$84	9,000	0.112
Delivered / imports	$514	$43	4,388	0.117
Exports	$496	$41	4,612	0.108
25-year Levelized Exports	$561	$47	4,433	**0.127**

I. Solar Costs

Q: DESC WITNESS EVERETT PRESENTS A CALCULATION OF RESIDENTIAL SOLAR COSTS, INCLUDING OFFSETS FOR FEDERAL AND STATE TAX CREDITS. DESC WITNESS SCOTT ROBINSON ALSO DISCUSSES THE ASSUMPTIONS FOR SOLAR COSTS USED IN HIS ADOPTION MODEL. PLEASE DISCUSS YOUR VIEW ON THE COSTS FOR CUSTOMERS WHO ADOPT SOLAR.

A: There is clearly a range of customer costs for residential and small commercial solar, based primarily on a range of capital costs in the market and whether a customer pays cash, finances the system, or signs a solar lease. I have used a

[15] The assumed degradation rate is 0.5% per year, which is a standard industry assumption also used by DESC (see DESC testimony [Robinson], at p. 5).

cash flow model for the levelized cost of energy (LCOE) for solar. My LCOE model uses capital costs for residential solar that are based on recent reported system costs in South Carolina.[16] The primary assumptions in my model are shown below in **Table 10.**

Table 10: Key Assumptions for the Levelized Cost of Residential Solar

Assumption	Value
Median Solar Cost	$3.10 per watt DC in 2020
Federal ITC	26% in 2020
State tax credit	25% capped at $3,500
Financing Cost	6%
Participant discount rate	5%
Financing Term	20 years
Inverter Replacement	$150 per kW-DC in Year 15
Maintenance Cost	$20 per kW-DC per year

The residential solar LCOEs that I have developed are 9.4 cents per kWh for cash purchases and 11.5 cents per kWh for loan-financed systems.[17] I use the latter value in my SPM tests.

J. Integration Costs

Q: HAS THE COMMISSION ADOPTED A COST TO INTEGRATE SOLAR INTO THE DESC SYSTEM?

A: Yes, it has. The avoided energy costs adopted for QFs in Order No. 2020-224 in Docket No. 2019-184-E include an interim Variable and Embedded Integration Charge of $0.94 per MWh. Thus, solar integration costs are included as an offset to the avoided energy costs calculated above. In the cost-effectiveness tests

[16] From the Energy Sage website, https://news.energysage.com/how-much-does-the-average-solar-panel-installation-cost-in-the-u-s/.
[17] Costs for leased system may be higher than this range, because leased systems do not qualify for the 25% state tax credit.

provided below, I have removed the integration costs from the avoided energy costs (on the benefit side of the tests) in order to show them as a distinct cost (on the cost side of the tests).

K. Societal Benefits

Q: DESC WITNESS EVERETT DOES NOT DISCUSS OR ATTEMPT TO QUANTIFY THE SOCIETAL BENEFITS OF SOLAR DERS THAT WOULD ACCRUE TO THE CITIZENS OF SOUTH CAROLINA. HAVE YOU QUANTIFIED SUCH BENEFITS, OR ARE YOU AWARE OF OTHERS WHO HAVE?

A: Yes. New renewable generation will supply a number of environmental and public policy benefits for DESC ratepayers and the citizens of South Carolina. These include:

- **Health benefits of reduced emissions of criteria pollutants.** Exposure to criteria air pollutants, including particulate matter, sulfur dioxide, and nitrogen oxides causes asthma and other respiratory illnesses, cancer, and premature death. Models and analyses from the U.S. Environmental Protection Agency (USEPA) can be used to quantify the health benefits of reducing these emissions from fossil fueled generation. ORS witness Mr. Horii cites a USEPA study that calculates benefits of $17 to $44 per MWh (in 2020 dollars) for solar generation that reduces criteria air emissions in the Southeast.[18]
- **Reduced methane leakage** is an additional environmental benefit of displacing natural gas use. It is a significant benefit because methane has about 100 times the greenhouse warming potential of carbon dioxide in the 20 years after it leaks to the atmosphere. Based on recent research estimating 1.9% leakage upstream of gas-fired power plants,[19] methane leakage significantly increases the carbon-equivalent emissions of gas-fired power plants, by almost 70%. As a result, it is important to account for these directly-related methane emissions from the production and pipeline

[18] ORS testimony (Horii), at p. 33.
[19] *See* Alvarez, Ramón A., *et al.* "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," *Science*, Vol. 361, No. 6398, 13 July 2018. Other research has determined that throughput on natural gas pipeline systems and methane leakage are highly correlated; thus, it is reasonable to assume that decreased throughput would result in decreased leakage. *See* He, Liyin, *et al.* "Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles," *Geophysical Research Letters*, Vol. 46, No. 14, 2019, at pp. 8563–8571.

infrastructure that would serve the gas-fired generation displaced by new solar generation. I calculate that the benefit of avoided methane leakage on the DESC system is $7.80 per MWh, based on avoiding the methane leakage associated with the marginal use of natural gas in power plants.

- **Additional benefits of reduced carbon emissions.** The societal damages from climate change have been quantified as the "social cost of carbon" (SCC). A recent estimate of the SCC for the U.S. is the median estimate of $417 per metric tonne from an academic review of a range of SCC values published in October 2018 in *Nature Climate Change*.[20] The SCC significantly exceeds estimates of the direct, compliance costs of controlling carbon emissions (such as the $25 per ton compliance cost assumed in the DESC IRP). Reducing carbon dioxide and methane emissions will have the additional social and economic benefit of avoiding these damages from climate change. This societal benefit can be measured as the SCC minus DESC's assumed carbon compliance costs, which results in a 25-year levelized benefit of $133 per MWh.
- **Land use benefits.** Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station solar plants require larger single parcels of land, and are more remotely located where the land has other uses for agriculture or grazing. Today, the land typically must be removed from this prior use when it becomes a solar farm. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land depends on the alternative use to which it could be put. The U.S. Department of Agriculture has reported the average value of agricultural land in South Carolina in 2019 as $3,400 per acre.[21] Assuming 3.9 acres per GWh per year, a $3,400 per acre value of land, and a 25-year loan at an interest rate of 5% per year to finance the land purchase, distributed solar provides a land use benefit of about $1 per MWh of solar output.

The societal benefits enumerated above total $172 per MWh, using the midpoint of the range of health benefits. This calculation does not include the direct and indirect economic impacts of net metered distributed generation to South Carolina set forth in Dr. Hefner's direct testimony.

[20] See Ricke et al., "Country-level social cost of carbon," *Nature Climate Change* (October 2018). Available at: https://www.nature.com/articles/s41558-018-0282-y.epdf.
[21] See https://downloads.usda.library.cornell.edu/usda-esmis/files/pn89d6567/g732dn07g/9306t9701/land0819.pdf.

Q: ARE THERE OTHER SOCIETAL BENEFITS FROM DISTRIBUTED SOLAR THAT ARE DIFFICULT TO QUANTIFY?

A: Yes. There are additional benefits of distributed solar resources that are difficult to quantify, but that the Commission should acknowledge and consider qualitatively. These additional benefits include:

- Rooftop solar enhances the **reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down.
- Distributed solar also enhances customers' **freedom, choice, and engagement** – allowing them to choose the source of their electricity and to produce much of it themselves on their private property. This results in customers who are more engaged and better informed about how their electricity is supplied.
- The choice of using private capital to install solar DG on a customer's premises leverages **a new source of capital** to expand South Carolina's clean energy infrastructure and allows the state to take full advantage of federal tax incentives for solar that have begun to phase out this year.

L. Cost Effectiveness

Q: HOW DO YOU PROPOSE EVALUATING SOLAR PV COST-EFFECTIVENESS?

A: As explained in my direct testimony, it is vital to examine the benefits and costs of distributed resources from multiple perspectives of each of the major stakeholders – the utility system as a whole, participating NEM/DER customers, and other ratepayers – so that the regulator can balance all of these important interests. Thus, the Commission should consider the results of the full suite of standard practice manual (SPM) tests for cost-effectiveness. I have assembled the benefits and costs of distributed solar discussed above into the five primary SPM tests. The following **Figure 4** and **Table 11** show the results for the five SPM tests on the DESC system.

Figure 4: *Summary of SPM Test Results*

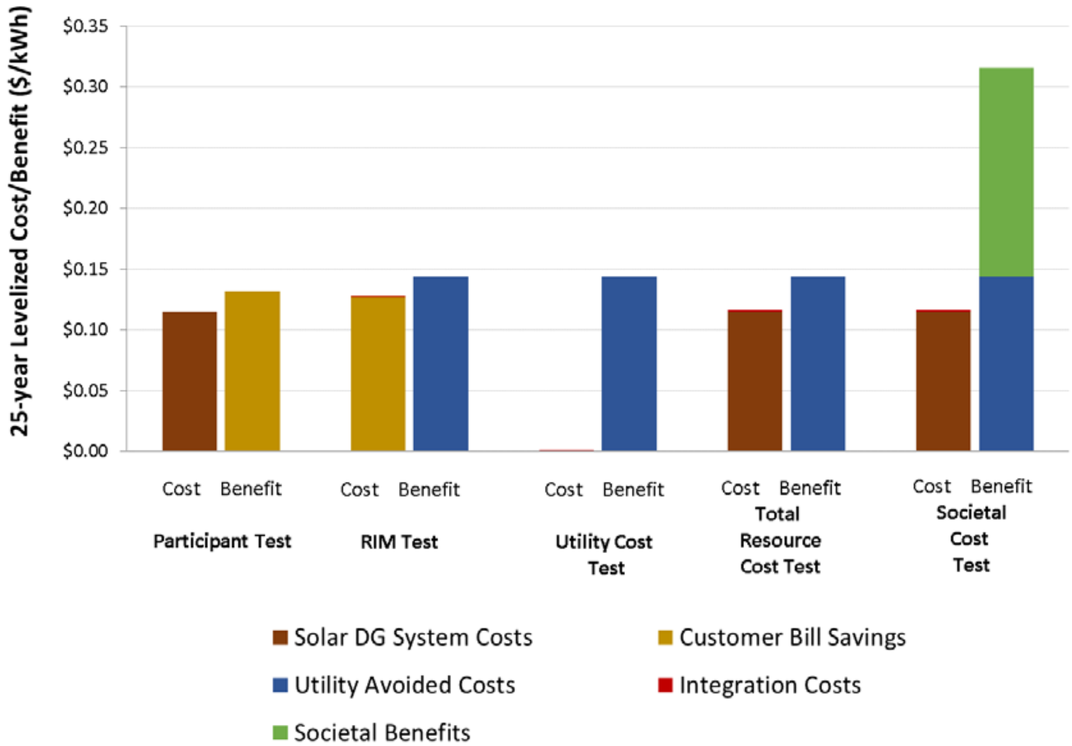


Table 11: Benefits and Costs of Solar DG for DESC (25-yr levelized $/kWh)

Benefit-Cost SPM Test	**Participant**		**RIM / UCT**		**Total Resource**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Direct Avoided Costs				0.144		0.144		0.144
Lost Revenues / Bill Savings		0.132 (all solar)	0.127 (exports)					
Integration			0.001		0.001		0.001	
Solar DG LCOE	0.115				0.115		0.115	
Societal Benefits								0.172
Totals	0.115	0.132	0.128	0.144	0.116	0.144	0.116	0.316
Benefit / Cost Ratios	**1.15**		**1.12 (RIM) >>1.00 (UCT)**		**1.24**		**2.72**	

Q: WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A: The results show that distributed residential solar on the DESC system passes all of the SPM tests. As a result, my principal conclusions are the following:

1. Solar DG is a cost-effective resource for DESC, as the benefits equal or exceed the costs in the TRC, Utility Cost, and Societal tests. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. Net metering does not cause a cost shift to non-participating ratepayers, including low-income customers, as shown by the results for the Ratepayer Impact Measure and Utility Cost tests.

3. Modifications to net metering are not needed to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed to recover the utility's full cost of service over time from net metering customers.

4. The economics of solar DG are marginal for DESC's residential customers, as shown by the Participant test results just above 1.0 and the modest amount of solar adoption to date. Thus, continuing the current compensation provided to solar DG customers could be important in maintaining the growth of this resource, particularly given the ongoing step-down in the federal tax credit.

5. There are significant, quantifiable societal benefits from solar DG, including public health improvements from reduced air pollution and from mitigating the damages from carbon emissions.

6. Solar DG also provides other important benefits that are difficult to quantify. These include the enhanced reliability and resiliency of customers' electric service, enhanced customer freedom, new sources of private capital to expand South Carolina's clean energy infrastructure, and an opportunity for the state's citizens to take advantage of federal tax incentives for solar.

IV. RESPONSE TO THE OFFICE OF REGULATORY STAFF

A. Cost-of-Service Issues

Q: ORS WITNESS BRIAN HORII EXPRESSES A CONCERN THAT THE DUKE ENERGY COST-OF-SERVICE STUDY FOR NEM CUSTOMERS USES A SUMMER 1 COINCIDENT PEAK ("1 CP") AS THE DEMAND METRIC. HE IS CONCERNED THAT THIS METRIC IS INACCURATE GIVEN THE RECENT WINTER PEAKS THAT DUKE HAS EXPERIENCED.[22] PLEASE COMMENT.

[22] ORS Testimony (Horii), at pp. 18-19.

A: ORS Witness Horii answers his own concern a few pages earlier in his testimony, where he clearly and correctly explains that both marginal and embedded cost-of-service (COS) analyses have roles to play in evaluating the reasonableness of a NEM tariff. Indeed, Act 62 explicitly calls for both to be considered in the design of the Solar Choice tariffs. He observes that an embedded cost-of-service analysis is important for "evaluating the policy issue of whether the solar customers would be paying their fair share of costs."[23] I agree that the essential purpose of a cost-of-service analysis, as performed in periodic rate cases, is to devise a fair allocation of the utility's costs among its customer classes. These costs are mostly historic costs incurred in the past, and therefore the allocators used to assign them to customer classes often will consider the demand drivers that caused them to be incurred in the past. From this perspective, Duke's use of the Summer 1 CP allocator is reasonable, as Duke historically has been predominantly a summer-peaking utility, with the winter peaks emerging only in a few recent cold snaps. That said, I agree with ORS Witness Horii that marginal cost information also is important to the design of the rates in the Solar Choice tariff, especially given that the marginal cost data is forward-looking, is more granular in time than the allocators in an embedded COS study, and focuses on the impact of a customer's choice on the margin to use and export on-site solar generation. I anticipate that, as the design of tariffs for small customers becomes more sophisticated – for example, by introducing various types of time-dependent pricing – the use of more granular marginal cost considerations will increase in importance. Act 62 clearly expects that there is a balance between the embedded and marginal COS perspectives that needs to be achieved in the Solar Choice tariff.

Q: WOULD THIS DOCKET BE THE APPROPRIATE PLACE TO MAKE CHANGES TO ONE OF THE ALLOCATORS IN DUKE'S EMBEDDED COST-OF-SERVICE STUDY?

[23] *Ibid.*, at p. 16.

A: No, it would not. A utility's embedded COS study is typically a major issue in general rate cases, where a broad range of parties have significant interests in how the utility's costs are allocated to its customer classes. Those rate cases are the correct venues in which all of the elements of an embedded COS study can be reviewed together, holistically, with all of the affected parties represented. The most recent rate cases for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) have approved embedded COS studies that include the Summer 1 CP allocator.[24]

B. Impacts on Low-Income Customers

Q: ORS WITNESS DR. JOHN RUOFF EXPRESSES CONCERN WITH THE IMPACTS ON LOW-INCOME CUSTOMERS OF ANY COST SHIFT FROM NET METERING CUSTOMERS TO NON-PARTICIPATING RATEPAYERS. PLEASE ADDRESS DR. RUOFF'S CONCERN.

A: Act 62 requires that the Solar Choice tariff should "eliminate any cost shift to the greatest extent practicable on customers who do not have customer sited generation."[25] With respect to DESC, the cost-effectiveness numbers presented in this rebuttal testimony indicate that there is presently no cost shift to non-participants under the current Act 236 policies and today's full retail net metering. This is demonstrated by net metering passing the Ratepayer Impact Measure (RIM) test for DESC residential customers. The RIM test is the most stringent test measuring impacts on non-participating ratepayers. Of course, the scope of this docket is limited to addressing the methodology for evaluating the Solar Choice tariffs. No actual Solar Choice tariffs have been proposed or evaluated, so it is premature to conclude whether there is a cost shift issue that needs to be addressed with those yet-to-be-filed tariffs.

[24] For DEC, see Order No. 2019-323 in Docket No. 2018-319-E (May 21, 2019), at p. 32 (Finding of Fact 33). For DEP, see Order No. 2019-454 in Docket No. 2018-318-E (October 18, 2019), at p. 3, specifically approving the company's COS study "to allocate all revenues, expenses, and rate base items and to design rates for all customer classes…."
[25] See Section 58-40-20(G)(1).

It is also important to note that the solar net metering tariffs—by themselves—have little to no effect on the longstanding affordability issues raised by ORS Witness Ruoff, especially given the positive cost-effectiveness results discussed above and the relatively low penetration of distributed solar in South Carolina today. Utilities can and should take proactive steps to address affordability of essential utility service for their low-income customers, including adopting efficiency programs that serve low-income households, establishing programs that make the benefits of solar accessible for low-income customers, and offering affordable rate designs with arrearage management and discounts to standard tariff rates. Those steps will have a profound and direct role in making utility service affordable.

Q: DOES A SOLAR CHOICE TARIFF HAVE TO PASS THE RIM TEST FOR THE COMMISSION TO CONCLUDE THAT THERE IS NO COST SHIFT ISSUE?

A: No. My direct testimony discussed at length the issues with the RIM test, and why the Utility Cost Test is more appropriate for evaluating a new, forward-looking program such as the Solar Choice tariffs. Further, the cost shift issue is a matter of equity among groups of ratepayers, and there are multiple ways to address any inequities. For example, the utilities, the solar industry, the Commission, and the state of South Carolina can develop programs to increase the access of low-income customers to solar technology, thus allowing low-income ratepayers to become participating customers – not just non-participants. In other states, the solar industry is a strong supporter and partner in such programs to expand solar access.

In addition, any weighing of equities among groups of ratepayers also should consider the societal benefits of clean DER technologies. These benefits include health benefits from reductions in emissions of criteria air pollutants and mitigating the damages of climate change. These benefits can be of particular importance to disadvantaged, low-income communities who often bear greater burdens from environmental degradation in the past and present. Expanding access to solar that is built in and by these impacted communities is particularly important to address the environmental justice issues that this history raises.[26]

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A: Yes, it does.

[26] Act 62 includes specific provisions to encourage community solar programs that can expand access to solar in low- and moderate-income communities. See Section 58-41-40.

CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served with a copy of the *Rebuttal Testimony of R. Thomas Beach* filed on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, Solar Energy Industries Association, and the North Carolina Sustainable Energy Association by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

Adam Protheroe, Counsel
S.C. Appleseed Legal Justice Center
Post Office Box 7187
Columbia, SC 29202
adam@scjustice.org

Jenny R. Pittman, Counsel
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jpittman@ors.sc.gov

Heather Shirley Smith, Deputy General Counsel
Duke Energy Carolinas/ Duke Energy Progress, LLC
40 W. Broad Street, Suite 690
Greenville, SC 29601
heather.smith@duke-energy.com

K. Chad Burgess, Director & Deputy General Counsel
Dominion Energy Southeast Services, Incorporated
220 Operation Way - MC C222
Cayce, SC 29033
chad.burgess@dominionenergy.com

J. Ashley Cooper, Counsel
Parker Poe Adams & Bernstein, LLP
200 Meeting Street, Suite 301
Charleston, SC 29401
ashleycooper@parkerpoe.com

Marion William Middleton III, Counsel
Parker Poe Adams & Bernstein, LLP
110 East Court Street
Suite 200
Greenville, SC 29601
willmiddleton@parkerpoe.com

Jeffrey M. Nelson, Counsel
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jnelson@ors.sc.gov

Matthew W. Gissendanner, Senior Counsel
Dominion Energy South Carolina, Incorporated
220 Operation Way - MC C222
Cayce, SC 29033-3701
matthew.gissendanner@dominionenergy.com

Jeffrey W. Kuykendall, Counsel
Attorney At Law
127 King Street, Suite 208
Charleston, SC 29401
jwkuykendall@jwklegal.com

Robert R. Smith, II, Counsel
Moore & Van Allen, PLLC
100 North Tryon Street, Suite 4700
Charlotte, NC 28202
robsmith@mvalaw.com

Roger P. Hall, Assistant Consumer Advocate
South Carolina Department of Consumer Affairs
Post Office Box 5757
Columbia, SC 29250
rhall@scconsumer.gov

Rebecca J. Dulin, Counsel
Duke Energy Carolinas/Duke Energy Progress, LLC
1201 Main Street, Suite 1180
Columbia, SC 29201
Rebecca.Dulin@duke-energy.com

Thadeus B. Culley, Regional Director and Regulatory Counsel
Vote Solar
1911 Ephesus Church Road
Chapel Hill, NC 27517
thad@votesolar.org

Peter H. Ledford, General Counsel and Director of Policy
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
peter@energync.org

This 29th day of October, 2020.

s/ Katherine Lee Mixson