BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2018-318-E

IN THE MATTER OF: Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order	))))))	**DIRECT TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF VOTE SOLAR**

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. Justin R. Barnes, 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years beginning in August 2007, where I worked as a Policy Analyst and then Senior Policy Analyst on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and efficiency policy.

I left N.C. State University in 2013 to join EQ Research as a Senior Policy Analyst, and later became a Project Manager and then Director. In my current position I coordinate EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry legislative, regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests. Outside of South Carolina, I have testified before the Colorado Public Utilities Commission, the New Hampshire Public Utilities Commission, the New Orleans City Council, the North Carolina Utilities

Commission, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, and the Utah Public Service Commission as an expert in distributed generation ("DG") policy, rate design, and cost of service.[1] My *curriculum vitae* is attached as Exhibit JRB-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE SOUTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony on behalf of The Alliance for Solar Choice in Commission Docket No. 2014-246-E addressing the implementation of 2014 Public Act 236, and in Docket Nos. 2015-53-E, 2015-54-E, and 2015-55-E addressing the applications of the state's three investor-owned utilities ("IOUs") to establish distributed energy resource programs pursuant to Public Act 236. I also submitted testimony on behalf of Vote Solar in Commission Docket No. 2018-319-E addressing the rates application of Duke Energy Carolinas ("DEC").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Vote Solar.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the rates application put forth by Duke Energy Progress ("DEP" or "the Company") on issues related to the Company's proposals involving residential basic facilities charges, AMI-enabled rate design, the South Carolina Grid Improvement Plan, and Excess Deferred Income Tax Rider EDIT-

[1] The New Orleans City Council regulates Entergy New Orleans in a manner similar to a state regulatory commission.

1. My testimony on all of these topics relates to cost of service and rate design. The purpose of my testimony is to show that:

1. The Company's proposed increase in the residential basic facilities charge, which if approved would be the highest residential customer charge in the country among IOUs, is based on a fatally flawed methodology, veers away from traditional principles of rate design, and wholly ignores prior Commission precedent rejecting the use of the Minimum System Method for distribution cost classification.
2. The proposed residential basic facilities charge would disproportionately increase the rates of low-usage customers and reduce the ability of customers to adopt solar energy and energy efficiency to manage their electric bills.
3. The Company's plan for deploying AMI-enabled rate designs and, consequently, allowing customers to realize the full benefits of AMI, lacks the specificity and detail necessary to inform the Commission of whether the Company's actions will result in just and reasonable rates.
4. The Company's proposed rate design for recovery of costs associated with its Grid Improvement Plan, to the extent the Commission permits it to move forward, inappropriately classifies costs and over-assigns revenue responsibility to the residential class, without consideration of whether residential customers would see equivalent benefits from Grid Improvement Plan investments.

5. The volumetric rate design that the Company proposes for the Excess Deferred Income Tax Rider EDIT-1 is unreasonable and should be revised to a percentage of bill-based design if the rider is approved in order to align it with the underlying causes of excess deferred income taxes.
6. Residential net metering customers provide an estimated benefit, in addition to any value of solar calculation, of roughly $84,000/MW-DC to the residential class by reducing the allocation of peak-driven costs to the class.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE RESIDENTIAL BASIC FACILITIES CHARGE.

A. My recommendations for setting the basic facilities charge are as follows:

1. The Commission should reject the changes the Company has made to its cost of service study and re-affirm precedent by directing the Company to eliminate the use of the Minimum System Method from its cost of service study.
2. The Commission should make a determination that the Basic Customer Method, which defines customer-related costs as those directly attributable to a customer's service connection, metering, billing, and customer service, is the appropriate method for classifying customer-related costs.
3. The Commission should reject the Company's proposed residential basic facilities charge and instead let it remain at its current rate of $9.06/month, which is a reasonable approximation of customer-related costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON AMI-ENABLED RATES, THE GRID MODERNIZATION PLAN, AND RIDER EDIT-1.

A. My recommendations on these topics are as follows:

1. AMI-Enabled Rate Design: The Commission should direct DEP to file a detailed AMI-enabled rate design plan within 60 days of a decision, and file two pilot rate proposals, one for residential customers and one for small non-residential customers, within six months of a decision. The Commission should also seek align the implementation of AMI-enabled rate designs in DEP's service territory with efforts undertaken by DEC as part of an integrated process in order to support fairness and administrative efficiency.
2. Grid Modernization Plan: The Commission should take several actions to ensure that the costs and benefits of the Company's Grid Improvement Plan are distributed equitably and that cost recovery is consistent with cost causation:
    a. Make a finding that Grid Improvement Plan investments cannot be considered part of a standard minimum distribution system because by their very nature they are extraordinary in character, regardless of whether the Commission accepts the use of the Minimum System Method in the Company's cost of service study.
    b. If the Commission approves the Grid Improvement Plan and the Company's proposed allocation and rate design generally, direct the

Company to revise the customer-related percentage calculation to fully exclude distribution plant associated with meters and service drops.

c. Direct DEP to perform cost-benefit evaluations that address the relative customer class distribution of costs and benefits at the project level, and align the allocation and recovery of costs with the results of the class-level cost-benefit evaluations and proper identification of energy and demand costs.

3. Rider EDIT-1: If the Commission approves Rider EDIT-1, the rate design should be revised to a percentage of bill-based mechanism in order to align it with the underlying causes of excess deferred income taxes.

II. DEP'S RESIDENTIAL BASIC FACILITIES CHARGE PROPOSAL

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR INCREASES TO BASIC FACILITIES CHARGES.

A. The Company proposes to increase the basic facilities charge for customers taking service under Schedule RES from the current amount of $9.06/month to $29.00/month. The increase proposed for Schedule R-TOUD, an optional residential time-varying rate with a demand charge component, is from $11.91/month to $31.85/month. Current and proposed basic facilities charges by broad customer class are shown in Exhibit No. 2 of the Direct Testimony of DEP Witness Steven Wheeler ("Wheeler Direct"). The proposed R-TOUD rate is not shown only in Wheeler Direct Exhibit No. 2, but can be found in the red-lined tariffs within Exhibit C to the Company's Application. Throughout my testimony

I generally refer to Schedule RES when discussing the Company's proposed charges for residential customers though the issues I identify are common to both Schedule RES and Schedule R-TOUD.

The Company's derivation of basic facilities charges rests in large part on its use of the "Minimum System Method", which classifies a significant portion of the costs associated with the shared distribution system (*i.e.*, upstream from customer's connection to the grid) as customer-related and therefore includable within the basic facilities charge.

Q. DO THE COMPANY'S PROPOSALS CONTAIN ANY CONSIDERATION OF CUSTOMER IMPACTS OR ELEMENTS DESIGNED TO MITIGATE ADVERSE IMPACTS GENERALLY, OR ON CERTAIN TYPES OF CUSTOMERS?

A. No. The proposed residential basic facilities charges are derived from costs that DEP's cost of service study classifies as customer-related, without modification.

Q. IS THIS LACK OF CONSIDERATION OF CUSTOMER IMPACTS NORMAL IN YOUR EXPERIENCE?

A. It is highly unusual. Even utilities that generally believe that higher residential fixed charges are appropriate based on the use of methodologies similar to the Company's typically seek to moderate the impact by proposing charges at lower amounts than those derived from their cost studies. This is one aspect of the ratemaking concept generally known as "gradualism", which seeks to avoid abrupt changes that would have large adverse impacts on one or more groups of customers.

DEP is no stranger to this concept. For instance, in its most recent North Carolina general rate case DEP contended that its cost of service study supported a residential basic facilities charge of $27.82/month, but it only proposed an increase from $11.13/month to $19.50/month in the interest of "minimizing the rate impact on low usage customers."[2] DEP further offered testimony in this case noting that when pursuing "cost justified" rates "it is important to consider the impact upon customers and to employ the principle of "gradualism"."[3] Therefore DEP proposed an increase in the residential basic facilities charge of roughly 50% of the difference between the existing charge and the theoretical charge indicated by the Company's cost of service study.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY ON THE COMPANY'S PROPOSED RESIDENTIAL BASIC FACILITIES CHARGES IS ORGANIZED.

A. In Section II-A, I describe in more detail how the proposals are an extreme departure from sound ratemaking principles and how those principles have been put into practice in other states, as evidenced by how dramatically the proposed rates differ and the amount of the associated increases compare to national statistics. In Section II-B I describe the considerable flaws in the methodology the Company uses to arrive at its proposed basic facilities charges. Section II-C of my

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[2] North Carolina Utilities Commission ("NCUC"). Docket No. E-2 Sub 1142. Direct Testimony of Steven Wheeler, p. 7, lines 17-18. June 1, 2017, *available at*: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=df403d03-f6a4-4c46-a6da-5fb9149b3499

[3] *Id.* p. 8, lines 15-17.

testimony contains an alternative calculation of customer-related costs based on eliminating those flaws.

A. The Company's Proposal Departs From Sound Ratemaking Practices

Q. PLEASE SUMMARIZE THE ELEMENTS OF GOOD RATEMAKING PRACTICE?

A. Good ratemaking is an exercise in balancing a suite of goals. The oft-cited work of Dr. James Bonbright offers valuable guidance on the criteria that should be used in the development of a sound rate structure, listing a set of eight principles to consider. I have paraphrased those principles that I believe are most relevant to this proceeding below:

1. The "practical" attributes of simplicity, understandability, public acceptability and feasibility of application.
2. Effectiveness in yielding total revenue requirements under the fair return standard.
3. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers (*i.e.*, gradualism).
4. Fairness of the rates in apportioning the total cost of service among different consumers.
5. Avoidance of undue discrimination.

6. Efficiency of the rate classes and blocks in discouraging wasteful use of service (*i.e.*, economic efficiency).[4]

The principles themselves are generally non-controversial. However, it is generally recognized that they are sometimes in conflict with one another, hence the need to achieve a balance. Prevailing rate designs for residential customers on the national level are indicative of how that balance is achieved in practice.

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL BASIC FACILITIES CHARGES COMPARE TO THOSE APPROVED BY REGULATORS IN OTHER STATES?

A. The proposed basic facilities charge for the residential class cannot be described as anything other than extreme. The proposed charge for Schedule RES would result in the *highest* fixed monthly charges placed on residential customers of any investor-owned utility ("IOU") in the country by a significant margin ($4.00/month higher than the current highest charge of $25.00/month).[5] Furthermore, they would result in increases far in excess in both monetary and percentage terms, of increases approved by regulators in other states during rate cases filed during roughly the last four years, other Duke Energy affiliates, and those of corporations deemed comparable to Duke Energy as described in the Direct Testimony of Robert Hevert.[6]

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[4] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 291.
[5] This refers to charges for "standard" service rather than optional rates.
[6] Direct Testimony of Robert Hevert ("Hevert Direct"), p. 17, Table 1.

Q. PLEASE SUMMARIZE THE RESULTS OF THE RESEARCH YOU CONDUCTED TO SUPPORT THIS CLAIM.

A. Table 1 below presents comparisons between current fixed monthly charge averages and DEP's current ($9.06/month) and proposed Schedule RES rate ($29.00/month). Table 2 presents averages of *increases* approved in rate cases filed during the last four years relative to the Company's proposed increase of $19.94/month, or 220%.

Table 1: Fixed Charge Comparisons

Basis of Comparison	Fixed Charge ($)	DEP Current Difference ($)	DEP Current Difference %	DEP Proposed Difference ($)	DEP Proposed Difference %
National Average	$10.42	-$1.36	-13.04%	**$18.58**	**178.34%**
DEP Affiliate Average	$10.21	-$1.15	-11.24%	**$18.79**	**184.11%**
DEP Comparables	$11.01	-$1.95	-17.69%	**$17.99**	**163.47%**
DEP Current	$9.06				
DEP Proposed	$29.00				

Table 2: Fixed Charge Increase Comparisons

Basis of Comparison	Increase ($)	Increase (%)	DEP Above ($)	DEP Above (%)
National Average	$0.94	13.55%	**$19.00**	**206.54%**
DEP Affiliate Average	$2.89	47.22%	**$17.05**	**172.87%**
DEP Comparables	$1.02	15.41%	**$18.92**	**204.68%**
DEP Proposed	$19.94	220.09%		

Table 1 shows that DEP's current residential customer charge is only moderately below the national average and the average for Duke Energy affiliates. Alternatively, though not presented in Table 1, the median fixed charge among IOUs, at $9.50/month, is lower than the simple average. DEP's proposed charge of $29.00/month is even more extreme relative to the median than the average.

The increase DEP proposes would place the residential customer charge well in excess of the national average and as shown in Table 2, and would dramatically exceed recent national averages for fixed charge increases and those awarded to Duke Energy affiliates. As with current fixed charges themselves, the median national increases in monetary and percentage terms are lower than the averages, at $0.25/month and 2.9%. In monetary terms, DEP's proposed increase is *more than 20 times* the average monetary increase approved in recent years by regulators in other states. The percentage increase is *more than 16 times* the national average percentage increase.

The five increases for Duke Energy affiliates in Table 2 refer to:

- A $0/month (0%) increase granted to Duke Energy Ohio in 2018 resulting in a current rate of $6.00/month.
- A $6.50/month (144.4%) increase granted to Duke Energy Kentucky in 2018 resulting in a current rate of $11.00/month.
- A $2.56/month (39.4%) increase granted to Duke Energy Progress (SC) in 2016 resulting in a current rate of $9.06/month.
- A $2.20/month (18.6%) increase granted to Duke Energy Carolinas (NC) in 2018 resulting in a current rate of $14.00/month.
- A $2.87/month (25.8%) increase granted to Duke Energy Progress (NC) in 2018 that results in a current rate of $14.00/month.

Combined, these translate to the $2.83/month and 45.65% averages reflected in Table 2.

Q. WHAT RESEARCH DID YOU CONDUCT TO DEVELOP THE DATA UNDERLYING THESE RESULTS?

A. I conducted a review of current residential customer charges for 172 IOUs in 49 states and the District of Columbia.[7] The utilities in this survey encompass all major IOUs and nearly all smaller IOUs in each state, thus the survey presents a comprehensive national picture of residential fixed charges. I also conducted a review of adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. A total of 178 general rate cases are represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame. Consequently, the sample of adopted increases reflects these utilities more than once. Both datasets are current as of February 8, 2019.

As I noted above, the "comparable" utilities are based on the proxy companies that DEP witness Hevert selected for his return on equity analysis. To generate these averages, I selected all of the local distribution utilities affiliated with these companies from my larger dataset of fixed charges and approved increases.

[7] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

Q. WHY DID YOU INCLUDE A COMPARISON TO COMPANIES "COMPARABLE" TO DEP IN YOUR ANALYSIS?

A. DEP Witness Hevert describes his selection of proxy companies as intended to consist of those with "risk profiles comparable to the subject company."[8] To be clear, none of his selection criteria involve an assessment of a company's risk profile based on revenue generated via fixed charges. However, it is inescapable that fixed charges do have the effect of providing a high degree of certainty for a portion of a utility's revenue during a given month or year (*i.e.*, little or no risk of under-recovery), making it less vulnerable to sales fluctuations.

I do not make any claims as to how fixed charge revenue may specifically affect a utility's risk profile. Nevertheless, I do believe that Mr. Hevert's list of proxy companies is illustrative insofar as it represents an additional basis for comparing different utilities, and shows results similar to the national and Duke Energy affiliate comparisons I have done. Certainly, the comparisons do not suggest that the Company's financial position presents a driving need for such a large increase in order to reduce its risk profile.

Q. SINCE YOU OBSERVE THAT GRADUALISM IS SOMEWHAT SUBJECTIVE, HOW DO YOU SUGGEST THE COMMISSION EVALUATE IT FOR THE PURPOSES OF SETTING THE BASIC FACILITIES CHARGE?

A. The national statistics I have presented on residential fixed charges and recent fixed charge increases are objective indicators of how gradualism is practiced for

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[8] Hevert Direct. p. 15, lines 11-12.

the purpose of setting residential fixed charges. Whether one considers the statistical means or medians the proper measure, the results are similar. Alternatively, gradualism is often practiced by relating fixed charge increases to the adopted percentage increase in class revenue. In this case, the Company's proposed residential class base revenue increase is roughly 14.0%.[9] That percentage increase equates to a residential basic facilities customer charge of $10.32/month. Such an approach is also objective because it stems from hard numbers rather than subjective judgments.

Q. DOES THE COMPANY'S BASIC FACILITIES CHARGE ADHERE TO THE PRINCIPLE OF GRADUALISM?

A. No, even using a very loose definition of the term. Duke Energy affiliates have recently sought large fixed charge increases in other jurisdictions, but none as drastic as what DEP has proposed here. As I have previously described, in North Carolina the Company reduced the amount of the proposed increase in the basic facilities charge by roughly 50% relative to the amount indicated by its cost of service study. While I disagree that the basis for the "cost justified" rate in its North Carolina cost of service study was accurate (as I do in the instant proceeding) or that the North Carolina proposal reflected a reasonable adherence to gradualism, the North Carolina proposal was at least somewhat more consistent with the principle.

In fact, the Company's basic facilities charge proposal in this proceeding is even more extreme than it appears at first glance. I say this because for the

[9] Based on Wheeler Direct, Exhibit No. 3 excluding riders and adjustment clauses.

purpose of establishing total class revenue requirements, the Company uses a rate impact mitigation formula shown in the Direct Testimony of Laura Bateman ("Bateman Direct") Exhibit No. 2 as the "reduction in variance from the average".

Thus for the purpose of determining class revenue requirements, the Company seeks to reduce how much class returns depart from the system average, but does not attempt to create full unity in terms of class rate of return at proposed rates. This reduces the overall residential class revenue requirement from what is indicated by the Company's cost of service study. However, the Company does not propose to make an equivalent downward adjustment in the proposed basic facilities charges, making the basic facilities charge an even larger component of overall rates than it would otherwise be.

Q. WHY SHOULD CUSTOMER PREFERENCES BE CONSIDERED IN RATE DESIGN?

A. Customer preferences are an element of public acceptability. Inherent in utility regulation is the idea that regulation should function as a substitute for competition. Since customers cannot select their electric distribution provider based on service characteristics or prices, regulation is critical for protecting them from being sold goods that they do not want or need at a given price point. Or, the corollary, to provide them with the services they do desire at a cost less than or equal to the value of the good. This concept has been referred to as using regulation to impose the "disciplines of competitive markets".[10]

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[10] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 17, REGULATORY ASSISTANCE PROJECT (2000), *available at:* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

There are broader consequences to this idea, involving the costs and benefits of utility investments and how they are distributed among customers, but it is also central to rate design. Since customers cannot make their preferences known by shopping around, those preferences must be discerned through other means, such as studies or rate pilots. Customer preferences fall within Bonbright's "practical attributes", and should be balanced with the other ratemaking goals such as economic efficiency, rate stability, and fairness at apportioning cost of service. Ideally, in replicating the function of a competitive market, a customer would have a suite of potential options to choose from that maintain this balance but also respond to their individual preferences.

Q. HAS THE COMPANY CONDUCTED ANY STUDIES OF CUSTOMER PREFERENCES REGARDING FIXED CHARGES?

A. DEP has participated in an Electric Power Research Institute ("EPRI") study to consider residential rate design choices. It is my understanding that, among other things, the study addresses consumer preferences regarding fixed charges though I have not been able to view the report because it requires a download fee of $25,000.[11] It has been conveyed to me that DEC has arranged for Vote Solar's counsel to review the study.

Q. WOULD IT BE REASONABLE FOR THE RESULTS OF THIS STUDY TO BE CONSIDERED IN THIS PROCEEDING?

A. Yes, and I say this without knowing the findings of the study. I leave how that could or should occur to the Commission to decide. That said, I find it troubling

[11] See the EPRI website at: https://www.epri.com/#/pages/product/000000003002013359/?lang=en-US.

that the Company possesses information that appears likely to be highly relevant to one of the most, if not the most, significant aspects of its application, which it cannot or will not make available to other parties.

Q. HOW WOULD THE COMPANY'S RESIDENTIAL BASIC FACILITIES CHARGE PROPOSALS AFFECT CUSTOMER BILLS?

A. Customers with relatively high usage would be advantaged, experiencing much lower increases in terms of percentage increase. Lower usage customers would be disadvantaged, experiencing rate increases well in excess of the average rate increase. For instance, the Company's collective rates proposals would cause a bill increase of $18.59/month (27.65%) for a customer on Schedule RES with average usage of 500 kWh per month. By contrast, a customer using 2,000 kWh per month would experience a similar monetary increase of $18.54/month but a much lower percentage increase (7.93%). Table 3 shows the breakdown of bill impacts for Schedule RES.[12]

[12] Sourced from Wheeler Direct, Exhibit No. 5, with "Amount of Increase" added as a new column.

Table 3: Schedule RES Rate Impacts at Different Usage Levels

Monthly kWh	Present Schedule Revenue	Proposed Schedule Revenue	Amount of Increase	Percent Increase
0	$9.06	$29.00	$19.94	220.09%
100	$20.70	$40.37	$19.67	95.04%
250	$38.15	$57.42	$19.27	50.49%
500	$67.25	$85.84	$18.59	27.65%
750	$96.34	$114.25	$17.92	18.60%
1000	$124.10	$142.00	$17.91	14.43%
2000	$233.80	$252.34	$18.54	7.93%
3000	$343.50	$362.68	$19.17	5.58%
4000	$453.21	$473.01	$19.81	4.37%
5000	$562.91	$583.35	$20.44	3.63%
6000	$672.61	$693.69	$21.07	3.13%

Q. WHAT TYPES OF CUSTOMERS WOULD BE MOST ADVERSELY IMPACTED BY THE LARGE INCREASE IN THE FIXED CHARGE?

A. Starting at the highest level, the majority of customers on Schedule RES are made worse off by fixed charge rates as opposed to volumetric ($/kWh) rates. A residential customer is indifferent to fixed versus volumetric charges at a monthly average use of roughly 1,200 kWh. In other words, if a fixed charge amount is translated to a volumetric charge that raises the same amount of revenue, a residential customer using 1,200 kWh per month would pay approximately the same amount as they would if the charge remained a fixed monthly amount. Customers using more than this indifference amount are better off with higher fixed charges, while those using lesser amounts are worse off. Roughly 56% of customers on Schedule RES use less than 1,200 kWh per month so the majority of that class is made worse off.[13] The farther a customer is from this indifference point in terms of average usage, the greater the impacts are, so lowest usage customers are the most adversely affected and the highest use customers stand to benefit the most.

One would expect customers with smaller homes, fewer or smaller devices and appliances, and non-electric heating to be made worse off because these customers could be generally expected to use less electricity. Schedule RES customers with on-site solar generation would generally be worse off as well, as average monthly usage among residential net metering participants as of 2017 was 824 kWh, significantly below the 1,200 kWh indifference threshold.[14] It is unclear how the rate impacts would vary by income level because the Company has not performed an analysis of low-income customer impacts.[15] However, it stands to reason that lower-income customers, who are more likely to reside in smaller residences and possess fewer or smaller electricity-using appliances, would also be relatively lower usage customers.

Q. IS THIS RESULT CONSISTENT WITH THE PRINCIPLES OF FAIR APPORTIONMENT OF COST OF SERVICE AND ECONOMIC EFFICIENCY?

A. No. It causes lower usage customers to subsidize higher usage customers and encourages wasteful use of service. The underlying causes of this outcome are the

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[13] DEP response to VS 1-7, Attachment "Annual AIR 1-14 DEP SC Blocking_Jan2017-Dec2017. Attached in Exhibit JRB-2, p. 4.

[14] DEP response to VS 1-36, Attachment "Vote Solar DR 1-36 - DEP Net Metering Statistics". Attached in Exhibit JRB-2, p. 14.

[15]DEP response to VS 1-12, attached in Exhibit JRB-2, p.8.

flaws in the Minimum System Method, which reflects a significant amount of demand-related costs as customer-related. In doing so, it eliminates the price signal that would otherwise be present in rates for the costs of that demand. A zero-load customer adds no demand to the system and therefore does not cause any additional costs beyond those required for grid connection. In other words, that customer does not impose any additional costs on the shared distribution system. That customer does not take up any "space" on the system that could otherwise be used to serve other customers. Yet that customer would still be required to pay for a considerable amount of demand-related costs through the Company's proposed basic facilities charge. I discuss this flaw in the Minimum System Method in more detail in Section II-B.

Q. WHAT ARE THE RESULTS OF RATES THAT FAIL TO ENCOURAGE ECONOMICALLY EFFICIENT CUSTOMER BEHAVIOR?

A. It dampens consumer incentives to save electricity, either through behavioral changes or investments in energy-efficient equipment and on-site generation such as solar. That in turn compels additional utility spending to meet those increased needs in the form of future generation, transmission, or distribution investments. This adds risk to the system since some future costs may not be possible to know with certainty (e.g., natural gas prices, coal ash remediation), whereas the present costs of demand-side investments can be known.

Fixed charges also directly increase the costs of demand-side programs that provide incentives for energy efficient equipment. By reducing customer savings potential, the incentive necessary to encourage the same amount of investment and achieve the same goals must be larger than it would otherwise be. For Schedule RES customers, at the maximum basic facilities charge I describe in the following section of my testimony ($9.23/month), the energy rate would have to be 1.62 cents/kWh higher to generate the same amount of revenue. A consumer replacing a conventional air-source heat pump with an Energy Star rated model would save roughly $45 less per year and more than $900 over a 20-year system lifetime under Company's proposed basic facilities charge relative my recommended charge.[16]

The foregone savings for even a moderately-sized on-site solar system would be much larger. A five-kilowatt ("kW") residential solar system could be expected to produce roughly 6,550 kWh annually in DEP's South Carolina territory.[17] Based on this, the foregone savings would be roughly $102 annually and more than $2,000 over a 20-year system lifetime. These impacts are sufficient to make material impacts on consumer investment decisions.

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[16] Based on default values in the Federal Energy Management Program's Energy- and Cost-savings Calculator for Energy-Efficient Products, *available at*: https://www.energy.gov/eere/femp/energy-and-cost-savings-calculators-energy-efficient-products

[17] Based on PVWatts outputs, for Florence, South Carolina, *available at*: https://pvwatts.nrel.gov/index.php. Estimate accounts for energy output degradation at 1% annually.

B. The Validity of the Minimum System Method

Q. HOW DOES THE COMPANY ARRIVE AT THE PROPOSED BASIC FACILITIES CHARGES?

A. The charges are based on the customer unit costs derived from the Company's embedded cost of service study. They represent the monthly payment that would be required to raise the revenue associated with costs that the cost of service study has classified as customer-related (*i.e.*, revenue divided by customer-months). Customer-related costs refer to those that vary in relation to the number of customers the utility serves, composed of costs associated with metering, billing, customer service, and customer service drops.

To these costs the Company's cost of service study adds allocations for more generalized administrative and general costs and classifies a significant portion of the shared distribution system that exists beyond the customer connection to the grid as customer-related. These shared distribution costs are composed of line transformers (FERC Account 368), secondary and primary overhead distribution lines (FERC Account 365), secondary and primary distribution lines (FERC Account 367), underground conduit (FERC Account 366) and secondary and primary distribution poles (FERC Account 364). I refer to these as the "shared" distribution system because unlike equipment such as meters or a customer's service drop, the shared components serve the system as a whole rather than individual customers.

The portion of the shared system that the Company classifies as customer-related, as opposed to demand-related, is derived using the so-called Minimum

System Method. The Minimum System Method is based on the premise that a portion of the shared distribution system is related to providing a customer with the ability to take electric service. In other words, it assumes that a certain number of poles and miles of wire are necessary to provide electric service even if a customer had only a minimal demand.

Q. HAS THE MINIMUM SYSTEM METHOD HISTORICALLY BEEN USED IN DEP'S SOUTH CAROLINA SERVICE TERRITORY?

A. My understanding is that it has not been used generally. In the Company's last South Carolina rate case, a portion of line transformer costs in FERC Account 368 was classified as customer-related, but remaining shared distribution costs were classified as demand related.[18] It is also worth noting that in 1991, on the recommendation of staff, Commission eliminated the use of the Minimum System Method from DEC's South Carolina cost of service study in favor of using a "more appropriate allocation factor."[19] The same rationale for its elimination in DEC's cost of service study applies to DEP.

Q. DO YOU AGREE THAT THE MINIMUM SYSTEM METHOD IS A VALID METHOD OF CLASSIFYING DISTRIBUTION SYSTEM COSTS AND DEVELOPING BASIC FACILITIES CHARGES?

A. No. It is not valid for either cost allocation or rate design, though more generally the distinction between cost allocation and rate design is one that should be appreciated. Rate design does not always have to, nor should it, replicate cost

[18] Direct Testimony of Janice Hager ("Hager Direct"), p. 12, lines 14-20.
[19] South Carolina Public Service Commission. Docket No. 91-216-E. Order No. 91-1022. p. 7. November 18, 1991.

allocation. It is sometimes appropriate to allocate certain costs in one way, but use rate designs that reflect consideration of other factors of cost causation. The Minimum System Method suffers from considerable flaws that make it unsuitable for either purpose. It should be discarded entirely in favor of more reliable and accurate methods of determining cost causation and responsibility.

Q. PLEASE DESCRIBE THE MINIMUM SYSTEM METHOD AND HOW IT AFFECTS RATEMAKING.

A. As I previously noted, the theory behind the Minimum System Method is that the distribution system is designed to not only serve customer demand, but also to connect customers regardless of their need for electricity. That is, it assumes that some costs of the shared distribution system are incurred solely for the purpose of connecting each customer. It generally relies on an examination of the book costs associated with each cost category (*e.g.*, poles and towers) to establish the costs associated with a hypothetical distribution system that serves some minimal amount of customer load.

In ratemaking, the results of a minimum system analysis influence how distribution costs are allocated between rate classes. This is because the allocators based on the number of customers in a class differ from those based on demand. Generally speaking, the result of more costs being classified as customer-related is a higher revenue requirement for classes with the largest number of customers (*e.g.*, the residential class). In practice, it also has a cascading effect because other cost allocators rely in part on the distribution-related allocators. Most directly, it causes a larger share of distribution system operation and maintenance ("O&M")

expenses to be classified as customer-related in line with the percentage of distribution plant that is classified as customer-related.

More indirectly, allocating more of the revenue requirement or more distribution plant to the residential class causes dynamic allocators based on net plant or share of class revenue to also increase. Finally, it may also influence how revenue is collected in the form of customer, demand, or energy charges to the extent that charges are based on the classification of costs (*i.e.*, customer costs collected via customer or basic facilities charges).

Q. HOW DOES THE COMPANY JUSTIFY THE CLASSIFICATION OF SOME PORTIONS OF THE SHARED DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A. Company Witness Hager relies on the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Allocation Manual ("Cost Allocation Manual"), which in her words "states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related."[20] Having read through the NARUC Cost Allocation Manual in detail on multiple occasions I can say that this statement mischaracterizes its purpose and its contents in several key ways. I will point to specific examples showing the inaccuracy of this statement later in my testimony.

[20] Hager Direct, p. 13, lines 4-6.

Q. DOES THE MINIMUM SYSTEM TRULY REPRESENT A ZERO-LOAD SYSTEM?

A. No. Company Witness Hager states that the Company's minimum system study is based on the infrastructure required to connect a customer with a *de minimus* load, like a light bulb.[21] However, in response to an information request, DEP stated that the analysis is based on the smallest equipment that the Company customarily installs.[22]

There is a large amount of daylight between what the Company typically installs versus what would actually be the smallest size equipment it would install if all customers had *de minimus* lighting loads. The Company actually has smaller-sized equipment on its system than what it chose for its minimum system analysis. That equipment is currently contributing to serving full customer loads. Thus not only is the Company's analysis not based on the smallest equipment necessary to meet a minimal load, it has more load carrying capability than some portions of the existing utility system that are serving the full demands of some customers.

In practice, it is not possible to accurately assess what a truly "minimum system" would look like because such a system would be so dramatically different from the current utility system and how customers use it. The departure from reality extends to all levels of the system. For instance, in a near zero-load system customer service drops would have smaller load carrying capacity and customer

[21] *Id.*, p. 14, line 19.
[22] DEP response to VS 1-2(a), attached in Exhibit JRB-2, p.2.

purchases of electricity would be so small that metering, billing, and customer service could be substantially simplified and less costly. Even meters themselves might be unnecessary from a cost-effectiveness standpoint, and it stands to reason that a near zero-load system would substantially affect the character of the transmission and generation system. Ultimately, the specification of a minimum system is a highly subjective departure from the reality of the system and how customers use electric service, and which is made increasingly anachronistic by growing customer loads and technological advances.

Q. PLEASE EXPLAIN HOW THE CONCEPTUAL FRAMEWORK OF THE MINIMUM SYSTEM METHOD IS ANACHRONISTIC.

A. In the early stages of electrification the concept of a minimum distribution system would have at least been closer to the reality of the system because electricity users were more dispersed and their electric loads were lower. That is, at some point in the past people desired to be connected to the electric grid to light a small number of light bulbs and perhaps sere a small electric appliance. Over time though, as electricity loads grow, the "single light bulb" scenario departs further and further from the reality of how customers use energy and why they desire to be connected to the grid. In addition, "grid modernization", represented by improvements such as those identified in the Company's Grid Improvement Plan, further upsets the notion that one can reliably identify a minimally-capable system.

The fact is that the equipment that a utility customarily installs now to provide electric service is substantially larger and capable of serving more load than what it would have installed decades ago. With recent technological advances in the arena of distributed generation, modern society would never choose to build a minimum distribution system because it would be more costly to do so than other options of providing equivalent electric service.

Q. PLEASE ELABORATE ON YOUR CONTENTON THAT MODERN SOCIETY WOULD NEVER CHOOSE TO BUILD A MINIMUM ELECTRIC SYSTEM.

A. In the modern day, if a person only desired electric service capable of lighting a single light bulb they would not need a connection to the grid at all. A small self-generation system composed of a solar panel and a small battery would be sufficient to meet these needs at a lower cost than connecting to the grid. Alternatively, customers might take service from small localized and isolated grids rather than an interconnected system of distribution, transmission, and centralized generation. Of course, a large grid exodus has not occurred because customers do not desire a minimum system, they desire a system that can meet their full electricity needs. Additional load beyond a bare minimum makes grid isolation far more challenging for a customer from both a practical and economic standpoint. The considerable complications of reliably serving their full demand at all times are what compel customers to connect to the grid in the first place.

I have performed a high-level analysis of the cost of providing electricity to a single light bulb from a grid isolated distributed generation ("DG") system. For the purposes of this analysis I assumed that the light bulb is a 17-Watt LED bulb, the modern equivalent of a 100-Watt incandescent light bulb. The power system is composed of a 300-Watt solar panel, a 100 Amp-hour deep cycle battery, and a charge controller. All of these items are available off the shelf at a local home improvement store. The total cost of such a system would be roughly $700, including $100 in miscellaneous costs apart from the solar panel, battery, and charge controller. In reality, in this hypothetical scenario the battery and solar panel are oversized relative to the reasonable need because even if one used the light consistently for 10 hours a day every day, a fully charged battery would store enough electricity for nearly nine days of lighting and an average day of solar production, even in the month of December, would be sufficient to provide more than four full days of lighting electricity.

At a total cost of $700, the monthly cost would be $5.86/month if the system lasted 10 years or $11.72/month if it had only a five-year lifetime.[23] It would fully pay for itself relative to the Company's proposed customer charge of $29.00/month in roughly two years. Of course, the solar panel, the single most costly portion of this system would last for at least 20 years. If one assumes a 5-year lifetime for the battery and charge controller, the 20-year cost would still only be $6.34/month. Again, these numbers are conservative because the on-site system is overbuilt relative to the actual electricity service need. Regardless, no reasonable customer would pay DEP's proposed basic facilities charge, or even the current basic facilities charge, if they only wished to serve a minimal load.

[23] The customer would also avoid having to a small energy charge, roughly $0.25/month if one assumes the same light bulb operation and an energy rate of $0.05/kWh.

The Company's hypothetical minimum system would never be built under these circumstances.

Q. IS THE MINIMUM SYSTEM METHOD GENERALLY ACCEPTED AS AN APPROPRIATE METHOD FOR CLASSIFYING DISTRIBUTION SYSTEM COSTS?

A. No. The Minimum System Method is based on the dubious premise that customers will pay to connect to the distribution grid even if they do not intend to use any electricity. A customer that has no demand for electricity would have no need to be connected to the distribution system. Distribution costs are caused by that demand and the customer density of a service territory, not by the presence of the customer. A zero- or minimum-demand customer of the type represented by the Minimum System Study or the Zero-Intercept variant simply does not exist.

Taken to its furthest extent, the flawed premise underlying the Minimum System Method effectively assumes that any distribution cost not proven to fall into another category must be customer-related. Dr. James Bonbright discusses this line of thinking in his seminal work *Principles in Public Utility Rates*. Dr. Bonbright acknowledges that one could devise a so-called minimum system, but dismisses the notion that the costs of that system are customer-related, referring to them as "unallocable".

> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). *Indeed, if the company's entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system…*

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs... while it is also denied a place among the customer costs...to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs...But fully-distributed cost analyst dare not avail himself of this solution, since they are prisoners of his own assumption that "the sum of the parts is equal to the whole." *He is therefore under impelling pressure to fudge his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of their other cost categories.* [24] [emphasis added]

Q. WHAT ARE THE IMPLICATONS OF THE HYPOTHETICAL MINIMUM SYSTEM HAVING THE ABILITY TO SUPPORT NON-ZERO CUSTOMER LOADS?

A. It causes demand to be double-counted. A given class receives an allocation based on the minimum system on a per-customer basis, but because that minimum system has some level of load carrying capability, it contains demand-related costs. That same class is then allocated the remaining distribution costs based on their full demands. This tends to have disproportionately large impacts on residential classes because those classes typically have the largest number of customers, and are allocated comparatively more of the costs the Minimum System Method classifies as customer-related.

In light of this criticism, an alternative method typically referred to as the Zero-Intercept or Minimum Intercept Method has sometimes been used to classify

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[24] Dr. James Bonbright, *Principles of Public Utility Rates*, p. 348-349, Columbia University Press (1961).

distribution system costs as customer- or demand-related. The Zero-Intercept Method uses statistical regression techniques to define the relationship between cost and load-serving capability. The result is a curve where equipment costs sit on one axis and load-serving capability sits on the other. Following the curve to the point where load-serving capability is zero (*i.e.*, the zero-intercept) produces an implied cost for equipment that is not capable of supporting any load.

Q. HAS THE COMPANY PERFORMED A ZERO-INTERCEPT ANALYSIS?

A. No. Company Witness Hager states that it has not done so because the analysis is more complex and often does not produce results much different than the Minimum System Method.[25] I find this explanation strange and unconvincing because the Company is clearly capable of performing complex analyses, such as a cost of service study or an integrated resource plan, and it is not possible to know whether such an analysis would produce results similar to the Minimum System Method unless one actually performs the study.

Q. DO OTHER STATES USE THE MINIMUM DISTRIBUTION SYSTEM METHOD FOR SETTING CUSTOMER CHARGES?

A. Many states confine the definition of "customer" costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the NARUC found that this "Basic Customer Method" (100% demand for shared distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report:

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[25] Hager Direct. p. 14, lines 6-9.

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[26]

In other states, some portion of the shared distribution system may be considered customer-related and allocated on that basis, but the methodology used can vary from state to state.

Rate design practices are likewise variable because rate design involves a balance of numerous competing objectives, such as fairness, stability, effectiveness at meeting revenue requirements, cost causation, and customer acceptance. The balancing reflects the fact that these objectives are frequently in conflict with one another. As I showed in Section II-A of my testimony, regulators have *never* adopted residential fixed charges at the level proposed by the Company.

Q. IS THE MINIMUM SYSTEM METHOD ENDORSED BY NARUC FOR COST ALLOCATION OR RATE DESIGN PURPOSES?

A. No. First, the NARUC Cost Allocation Manual, as indicated by its title, addresses only cost allocation. It does not purport to address rate design based on the results of embedded cost studies. Second, the Cost Allocation Manual refers to the Minimum System Method as *one* method of classifying distribution costs, but it

[26] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, REGULATORY ASSISTANCE PROJECT (2000), *available at:* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

does not endorse any method in particular. The preface expressly states this in the context of the objectives for the document, as follows:

> The writing style should be non-judgmental, not advocating any one particular method, but trying to include all currently used methods with pros and cons.[27]

The section on distribution cost allocation protocols goes on to note that the results are directly related to the assumptions used, such as how the minimum size distribution equipment is selected. Furthermore, the document includes statements advising readers of methodological concerns present with the Minimum System Method and highlighting that the issue of distribution cost classification is in no way settled, as follows:

> [M]inimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[28]
>
> The major issue in establishing the marginal cost of the distribution system is the determination of *what costs, if any, should be classified as customer related*, rather than demand and energy related. *The issue is a carry-over of the unresolved argument in embedded cost studies* with the added query of whether the distribution costs usually identified as customer related are, in fact, marginal.[29] [emphasis added]

Contrary to Company Witness Hager's statements, the Cost Allocation Manual does not affirm the Minimum System Method, or any method for that matter, as the "right" way to allocate costs of the shared distribution system. Furthermore, it does not endorse the use of unit costs derived from cost allocation

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[27] NARUC. Electric Utility Cost Allocation Manual. p. ii. 1991.
[28] *Id.* p. 95.
[29] *Id.* p 136.

studies for setting the rates for different types of charges, such as basic facilities charges.

Q. DO YOU SUPPORT THE USE OF A ZERO-INTERCEPT STUDY TO IDENTIFY CUSTOMER AND DEMAND-RELATED COMPONENTS OF THE SHARED DISTRIBUTION SYSTEM?

A. No. A Zero-Intercept analysis would be better than what the Company has put forth since it at least attempts to isolate and remove the demand component to avoid double-counting. However, it still fails to reflect the fact that a zero-load customer would have no need to be connected to the grid.

Q. WHAT APPROACH DO YOU THEN RECOMMEND THAT THE COMMISSION ADOPT FOR THE CONDUCT OF COST OF SERVICE STUDIES?

A. I recommend that the Commission use the Basic Customer Method because it more reliability avoids any double-counting of demand, is far simpler to execute, and is more broadly accepted as an appropriate mechanism. Furthermore, it reduces the downstream effects that classifying any portion of shared distribution system has on other dynamic allocators that derive in part from how distribution plant is classified. This avoids rendering the customer costs category "a dumping ground" for unallocable costs that Dr. Bonbright cautions against.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS ON THE COMPANY'S MINIMUM SYSTEM STUDY AND THE ACCOMPANYING IMPACTS IT HAS ON THE COMPANY'S COST OF SERVICE STUDY, COST ALLOCATION, AND RATE DESIGN?

A. Yes. As I previously observed, the Minimum System Method tends to result in the more costs being allocated to the residential class because it defines more costs as customer-related and the residential class has more individual customers than other classes. Therefore, if class rates of return under present rates are evaluated, the residential class shows a lower rate of return than it would without a minimum system assumption. As shown in Bateman Direct Exhibit No. 2, with the Minimum System Method incorporated into the Company's cost of service study, the return at present rates for the collective residential class is 2.71% while the system-wide return is 4.10%. This suggests that the residential class is underperforming by a significant amount relative to other classes (*i.e.*, being subsidized by other classes).

However, with the minimum system assumption removed, the residential class shows a return at present rates of 3.36%, still lower than the system average but a sizable improvement. Discarding the Minimum System Method also reduces the range of class variances from the system average rate of return, meaning that class returns under current rates, variances from unity, and class returns based on the final proposed revenue requirement are clustered more tightly around the system average.[30]

Q. WHAT IS THE SIGNIFICANCE OF THIS OBSERVATION?

A. The significance is twofold. First, removing the minimum system assumption produces a more rational and consistent result with a lesser need for rate impact mitigation. Second, it shows that historic allocations and current rates have performed fairly well in terms of producing similar class returns, and correspondingly, the appearance of significant inter-class subsidies. In other words, nothing suggests that the current system is "broken" in some way, and consequently suggestive of any need for modification.

<u>C. An Appropriate Maximum Residential Customer Charge</u>

Q. WHAT IS THE APPROPRIATE BASIS FOR SETTING RESIDENTIAL CUSTOMER CHARGES?

A. The customer charge should reflect the cost of a customer that does not impose a demand or consume energy. This cost is represented by the incremental cost of connecting a customer (*i.e.*, the marginal cost), which is generally limited to the costs for a meter and service drop along with expenses for meter reading, billing, and customer service.[31] Another way to view the appropriate role of the customer charge that typically produces a similar result is to define customer-related costs

[30] Based on a comparison of Bateman Direct Exhibit No. 2 and DEP response to VS 1-8, Attachment "DEP VS DR 1-8 Bateman 2 No Min" attached in Exhibit JRB-2, p.6.
[31] Jim Lazar & Wilson Gonzalez, *Smart Rate Design for a Smart Future*, at 36, REGULATORY ASSISTANCE PROJECT (July 2015), *available at*: http://www.raponline.org/document/download/id/7680.

as those that vary directly with the number of customers.[32] However, it is a mistake to conflate the costs associated with such a zero-load customer with costs that are not directly correlated with customer demand or energy consumption. Many joint system costs vary more indirectly with one or more cost categories and consequently do not fall neatly within the customer, demand, or energy classification.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S COST OF SERVICE STUDY, WHAT WOULD BE A REASONABLE MAXIMUM RESIDENTIAL CUSTOMER CHARGE?

A. The Company's cost of service study shows that if the Minimum System Method is removed, the basic facilities charge for residential customers based on the customer unit cost is $9.81/month.[33] I have calculated a reasonable *maximum* residential customer charge of $9.23/month, based on eliminating the use of the Minimum System Method and then excluding two other cost components classified exclusively as customer-related in the Company's cost of service study. I emphasize that this is a reasonable *maximum* charge because the cost of service outputs that I have access to do not permit the cost components of the customer unit cost to be examined at a granular, FERC Account level. Consequently, my calculated maximum likely overstates the costs that are reasonably classified as customer-related.

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[32] *Id.* at 83.

[33] DEP response to VS 1-20, Attachment "ORS AIR 13-4 Wheeler Exhibit 2 wo Min System", attached in Exhibit JRB-2, p. 12. This response lists a customer unit cost of $9.91/month. However, using the number of customer-months the Company uses in its rate design calculations, the equivalent basic facilities charge is $9.81/month.

Q. WHAT COST COMPONENTS HAVE YOU EXCLUDED FROM THE CALCULATION OF THE MAXIMUM RESIDENTIAL CUSTOMER CHARGE IN ARRIVING AT THE $9.23/MONTH FIGURE?

A. The costs I have excluded, and the reasons I excluded them are as follows:

1. AMI Amortized O&M: AMI serves energy- and demand-related functions far beyond the simple measurement of customer consumption for billing purposes, and the customer charge already includes the cost of non-AMI metering via recovery of the un-depreciated costs of those meters.
2. Uncollectable Accounts: Uncollectables are a general cost of doing business that does not have any relationship to the customer's connection to the grid. Actual collection expenses are logged separately along with customer records. I have not excluded any of those costs.

Q. YOU PREVIOUSLY STATED THAT COSTS THAT VARY DIRECTLY WITH THE NUMBER OF CUSTOMERS ARE REASONABLE TO INCLUDE IN THE CUSTOMER CHARGE. PLEASE THEN EXPLAIN MORE DETAIL WHY YOU EXCLUDED AMI COSTS IN YOUR CALCULATION.

A. While it is true that metering and associated metering costs are typically recovered through fixed monthly charges, AMI is not "typical" metering. As I previously stated, fixed customer charges should recover the cost of connecting a customer to the grid. Advanced metering and the associated incremental costs above traditional meters are not strictly necessary for the customer to be connected to the grid. A non-advanced meter and associated infrastructure can do so at lower costs. AMI is used for much more than measurement of a customer's consumption for billing purposes. Furthermore, since customers do not have a meaningful choice of whether to take service through an advanced meter from a cost perspective, those customers are not truly "causing" the incremental advanced metering costs. Treating AMI costs exclusively as customer-related just because they relate to "metering" and consequently recovering them through a fixed charge is an oversimplification of the cost causation factors at play.

Q. SHOULD THE COMMISSION ATTRIBUTE THE COSTS OF AMI AS RELATED PRIMARILY TO PRODUCING ENERGY AND PEAK DEMAND SAVINGS?

Yes. The incremental costs of AMI above traditional metering are more accurately viewed as primarily energy- and/or demand-related because AMI deployment is generally undertaken with a goal of producing system cost savings associated at least in part with energy- or demand-related functions, or system operation and reliability. Furthermore, including these costs as a component of a fixed monthly charge works at cross-purposes with the goal of enabling greater customer control over their energy bills. Finally, it is fundamentally unfair to require customers to effectively pay two fixed metering charges at the same time, one for the un-depreciated cost of legacy meters and one for AMI infrastructure and associated O&M costs.

Q. ARE CUSTOMERS CURRENTLY BENEFITTING FROM AMI DEPLOYMENT?

A. From the perspective of operational cost savings reflected in the 2017 test year it does not appear that they receive a tangible cost savings benefit because AMI deployment did not begin until May 2018.[34] Company Witness Schneider discusses the benefits of AMI in broad terms, including the potential for operational cost savings, but does not provide any specific cost savings estimates.[35] Thus customers would pay the $0.5 million annual revenue requirement associated with the Company's AMI amortization proposal.[36] However, that cost would not offset by operational savings reflected in the rates those same customers pay.

Q. ARE THE COMPANY'S STATED JUSTIFICATIONS FOR AMI DEPLOYMENT CONSISTENT WITH THE GOAL OF PRODUCING ENERGY AND DEMAND COST SAVINGS?

A. Unfortunately, the Company's plans in this area lack specificity and to my knowledge the Company has not conducted a cost-benefit analysis of AMI deployment in South Carolina. Company Witnesses Hunsicker and Wheeler obliquely reference AMI, coupled with the new Customer Connect system, as enabling its ability to offer more advanced rate designs in the future. For instance, Company Witness Hunsicker states that the system will allow for more flexible rate designs, further noting that "New modern CISs are more configurable

[34] Wheeler Direct, p. 11, line 2.
[35] Direct Testimony of Donald Schneider ("Schneider Direct"), p. 10-12.
[36] Bateman Direct, p. 23, lines 9-10.

reducing the amount of time to test and implement pricing changes and offerings."[37] Company Witness Wheeler notes that while the Company has not proposed any new peak or real-time pricing designs, it continues to review "rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service."[38] Company Witness Wheeler also observes that CIS upgrades described by Company Witness Hunsicker will "better support these types of designs" and that current metering does not provide the interval data necessary to support "these innovative designs."[39] The broad implication of statements like these is that AMI, as well as the Customer Connect system, are integral components for unlocking energy and demand-related benefits.

In addition, the AMI cost-benefit analysis the Company was ordered to conduct in North Carolina provides useful information on this topic, showing that expected AMI benefits to customers are dominated by benefits unrelated to customer-specific costs. Roughly 31% of the estimated long-term benefits display a clear connection to the customer classification, composed of reduced metering reading costs, reduced meter operations costs (including remote connection and disconnection), and reduced failure of legacy meters. The remaining benefits are associated with outage restoration O&M, "miscellaneous" O&M, capital cost savings such as distribution loading analysis and improved capacitor bank placement, and "non-technical line loss reduction".[40]

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[37] Direct Testimony of Retha Hunsicker ("Hunsicker Direct"), p. 12, lines 1-8.
[38] Wheeler Direct, p. 10, lines 17-19.
[39] *Id.* p. 10, lines 19-23.
[40] NCUC. Docket No. E-100, Sub 147. 2017 Smart Grid Technologies Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC. October 2, 2017. Appendix C, Exhibit A, *available at*: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=21f06c4c-f377-4425-a865-65b777e6a18b

Non-technical line loss reduction provides the single largest estimated benefit, totaling roughly 57% of total estimated benefits.[41] This category of benefit refers to additional revenue capture from a reduction in instances of meter non-performance, power theft, equipment errors, and misconfiguration.[42] Such revenue erosion is a generalized cost of doing business without any clear tie to customer-related utility functions somewhat akin to uncollectable accounts. When decisions about the merits of AMI deployment are based on future customer benefits of this type, the cost of AMI is properly attributable to achieving those benefits.

Furthermore, while the Company has not provided any analysis of potential energy and demand savings enabled by AMI via advanced rate designs, it is generally accepted and recognized that such future savings are one of the primary reasons for AMI deployment. As I discuss in more detail later in my testimony, North Carolina regulators have expressly emphasized peak demand and energy savings as a key benefit of AMI deployment. I encourage the Commission to do so here as well, both from the perspective of the rate design for AMI cost recovery and the need for prompt development of innovative rate designs that make these savings possible.

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[41] *Id.*
[42] *Id.* Appendix C, Exhibit F.

Q. ARE YOU SUGGESTING THAT AMI COSTS BE ALLOCATED IN A MANNER OTHER THAN ON A PER CUSTOMER BASIS?

A. No. AMI costs vary directly with the number of meters that must be installed. Therefore, it is reasonable to allocate these costs based on the number of customers. The residential class requires more meters therefore it should bear an equivalent portion of the costs. However, rate design should reflect the fact that the costs are not attributable to the decisions of individual customers, and that the incremental costs of AMI are related primarily, if not exclusively, to long-term energy and demand cost savings for individual ratepayers and the system as a whole.

Q. GIVEN THAT AMI AND THE COMPANY'S CUSTOMER CONNECT SYSTEM ARE PART OF AN INTEGRATED PLATFORM, HAVE YOU MADE ANY ADJUSTMENTS TO HOW THE COSTS OF CUSTOMER CONNECT ARE APPROPRIATE TO REFLECT IN RATE DESIGN?

A. No, but such an adjustment could be reasonable. The Customer Connect system is an integral element to realizing the full value of AMI (and its associated benefits) and is designed to possess capabilities far beyond those necessary for simple billing purposes. It follows that a portion of Customer Connect costs likewise have an energy- and demand-related purpose. If 50% of Customer Connect expenses related to O&M and depreciation and amortization were removed from the customer-related classification, my calculation of a maximum reasonable basic facilities charge would be reduced by $0.42/month to $8.81/month.

Q. PLEASE EXPLAIN WHY YOUR CALCULATION OF A $9.23/MONTH MAXIMUM RESIDENTIAL CUSTOMER CHARGE MAY ACTUALLY OVERSTATE A REASONABLE MAXIMUM CUSTOMER CHARGE.

A. Ideally, the cost components should be evaluated at the FERC Account level and direct assignment of costs should be used whenever possible. This is the method that the Connecticut Public Utilities Regulatory Authority ("PURA") arrived at when devising a methodology to determine a Maximum Residential Customer Charge ("MRCC) in response to 2015 legislation limiting residential customer charges to costs directly associated with billing, metering, customer service, and the customer's service connection. I find the PURA's examination of the topic to be a thorough, well-reasoned, and readily understandable evaluation of the costs directly attributable to metering, billing, customer service, and the customer's service connection.[43] [44]

In DEC's most recent South Carolina rates proceeding I was able to perform a more granular examination at the FERC Account level, though it was not possible to make any direct assignments for certain costs. In the DEC proceeding, I additionally excluded several distribution O&M accounts, sales and advertising expenses, and several depreciation and amortization adjustments that bear no relationship to metering, the customer connection, billing, or customer service. I also observed that, in line with the PURA's methodology, general and

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[43] Connecticut Office of Legislative Research. *Maximum Residential Customer Charge Research Report*. June 12, 2018, *available at*: https://www.cga.ct.gov/2018/rpt/pdf/2018-R-0151.pdf.

[44] PURA Docket No. 17-01-12. Final Decision dated December 20, 2017, *available at*: http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/484ed9e80c8e0044852581fc0070a1f6?OpenDocument.

administrative costs required a closer examination and consideration of direct assignment, though it was not possible for me to do so.[45]

Based on the cost of service study outputs that I possess for DEP, none of this was possible because the resulting spreadsheets group many FERC Accounts together into broad categories and it is generally not possible to discern what portion, if any, has been classified as customer-related. The one possible exception to this are sales and advertising expenses, which are classified entirely as customer-related though not specified at the FERC Account Level. Since I could not identify the specific accounts associated with these expenses, and as a consequence whether some of the costs may relate to direct customer service activities, I did not exclude them. However, had I done so, my maximum charge estimate would have been $0.32/month lower, resulting in a maximum customer charge of $8.91/month.

Q. AT WHAT AMOUNT DO YOU RECOMMEND THE COMMISSION SET THE RESIDENTIAL BASIC FACILITIES CHARGE?

A. I recommend that the residential basic facilities charge be left at its current rate of $9.06/month. While my maximum charge estimate of $9.23/month is slightly higher than this, there is good reason to believe that it contains costs that should not be classified as customer-related. A more granular evaluation could reveal that the basic facilities charge should in fact be set lower than the current rate. Notwithstanding these uncertainties, the current rate is a reasonable

[45] South Carolina Public Service Commission. Docket No. 2018-319-E. Direct Testimony of Justin R. Barnes on behalf of Vote Solar. February 25, 2019, p. 39-43.

approximation of customer-related costs given available information so maintaining it without change is a simple and reasonable outcome.

III. SOLAR BENEFITS IN COST OF SERVICE

Q. PLEASE EXPLAIN IN GENERAL HOW ON-SITE SOLAR GENERATION AFFECTS AN EMBEDDED COST OF SERVICE STUDY?

A. On-site solar generation helps avoid both current and future costs. I focus here on how on-site solar affects the allocation of costs in the Company's embedded cost of service study. In this frame, on-site solar generation reduces and shifts load placed on the generation, transmission, and distribution system by way of reductions in customer loads and exports to the grid. This load reduction and shifting translates to changes in both jurisdictional and South Carolina retail class allocations. That is, when on-site solar generation reduces load in South Carolina at the time of the Company's summer coincident peak, South Carolina customers are allocated fewer costs for utility functions for which allocators are based on contribution to the system peak (*i.e.*, production demand and transmission). The same effect occurs at the retail customer class level.

A similar effect can occur at the distribution level, for which costs are allocated based on non-coincident class peak demand. While solar does not generally reduce the non-coincident peaks of individual customers, it can do so at the customer class level if the timing of the class peak coincides with a time period where solar production is occurring. By reducing class demand at that hour, solar may equivalently reduce the class peak to a lower amount, or may cause the class peak hour to shift to another hour with a lower class peak (*i.e.*, the reduction may not have a 1:1 relationship to generation).

Q. CAN THE IMPACTS OF THESE AFFECTS BE QUANTIFIED?

A. Yes. I have constructed an estimate of the amount saved per MW-DC of residential net-metered solar generation at the time of the Company's test year coincident peak, composed of reduced production demand and transmission demand costs allocated to the residential customer class. I was not able to calculate an actual savings number based on actual residential net-metered solar production at the time of the retail summer peak because the Company could not provide the production data necessary to make such an estimate (*i.e.,* metered production data at the time of the peak). However, I have estimated that net-metered residential solar production would have reduced costs allocated to the residential class by roughly $84,000/MW-DC.[46] This amount is composed of roughly $32,500/MW-DC representing the residential class's share of jurisdictional cost savings and roughly $51,400/MW-DC representing South Carolina retail allocation savings. Other classes benefitted from the remaining jurisdictional cost savings of approximately $46,500/MW-DC.

Q. PLEASE EXPLAIN HOW YOU MADE THESE CALCULATIONS.

A. I first developed an estimate for what residential solar production would have been at the time of the retail system peak, the hour ending at 5 PM on July 13, 2017. For my estimate, I used PVWatts to develop an average solar capacity factor for the hour ending at 5 PM during the month of July. This is reflective of a

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[46] This assumes that solar production at the time of the summer peak is fully and properly accounted for in the allocation process.

"typical meteorological year" as used by PVWatts. I also grossed up the expected solar capacity contribution for line losses.

I used this capacity contribution to calculate revised production cost allocators that reflect a no residential solar assumption. To do this I added the solar capacity contribution to applicable system-wide, South Carolina, and residential class peaks. These alternates produce higher percentage allocators to South Carolina and the South Carolina residential customer class. Applying the percentage differences to the sum of retail production demand and transmission demand revenues produces the monetary benefits estimate.[47]

Q. DOES THIS REFLECT THE FULL RANGE OF BENEFITS PRODUCED BY NET METERED SOLAR SYSTEMS TODAY?

A. No. It only reflects an expected contribution from residential systems at the time of the 2017 test year peak on a unit basis. Non-residential solar savings may differ on a unit basis (*e.g.*, different capacity factors and allocation percentages) and estimating gross class savings requires scaling to the actual amount of capacity on the system at the time of the peak. Those gross savings amounts will persist as an annual benefit until a new cost of service study is conducted and reflected in rates because they are based on annual revenue amounts.

In addition, the savings amounts do not reflect potential residential class benefits from reductions in non-coincident class peak due to direct reductions or shifting. The data necessary to conduct an examination of this potential source of

[47] An estimate of system-wide production and demand revenue requirements was derived by scaling South Carolina retail revenues based on the ratio of South Carolina retail production demand to total system-wide production demand.

savings is not available. They also do not reflect the incremental value of net metered energy generation, as reflected in difference between the marginal time differentiated value of net metered generation and the base energy rate.

Q. WHAT IS THE SIGNIFICANCE OF THE SAVINGS DATA YOU HAVE PRESENTED HERE?

A. Beyond contributing to long-term cost savings based on avoided future costs, residential net-metered solar is currently producing recurring, tangible cost savings for the residential class and for South Carolina retail customers as a whole. The magnitude of the benefit is directly correlated with the amount of residential behind the meter solar capacity on the system.

IV. DEPLOYMENT OF INNOVATIVE RATE DESIGNS

Q. HAS THE COMPANY DEVELOPED ANY CLEAR PLANS FOR DEVELOPING AND DEPLOYING INNOVATIVE OR ADVANCED RATE DESIGNS?

A. No. As I mentioned previously, Company Witnesses Hunsicker and Wheeler make vague references to AMI-enabled rate designs in their testimony, but do not articulate any specifics in terms of the timing or character of future offerings. Company Witness Hunsicker notes that Customer Connect Platform, which is an important element of implementing new rate designs, will not be fully placed in service until 2021.[48]

[48] Hunsicker Direct. p. 12, lines 17-18.

Q. WOULD IT BE REASONABLE FOR THE COMPANY TO DEFER DEVELOPING INNOVATIVE RATE DESIGN OPTIONS UNTIL AMI AND THE CUSTOMER CONNECT SYSTEM IS FULLY OPERATIONAL?

A. No, for several reasons. First, developing new rate designs that respond to both customer preferences and produce system savings is not a quick process. It takes time to design new rates for deployment on a pilot basis, more time (a year or more) to conduct the pilots, time to evaluate the results, and more time to come up with permanent rate options. It would not be unusual for such an effort to extend over several years since the process must generally proceed in a step-wise fashion.

Ideally, rate pilots, or at least the planning activities for pilots, are activities conducted in advance of full deployment or concurrently while deployment is taking place. It is not unusual for regulators to require rate pilot plans as part of applications seeking approval to deploy AMI, or to condition approval of AMI deployment on the prompt commencement of planning and rate pilot development. The rationale for this type of progression is that since customers are paying for AMI deployment (or presumably will be at the conclusion of this rate case for DEP), they should be provided with opportunities to take advantage of AMI capabilities as early as possible. This in part reflects a standard of ratemaking that conditions cost recovery on investments being used and useful. Persistent under-utilization calls the reasonableness of cost recovery into question.

Second, in order to ensure that the overall integrated system is capable of supporting the rate designs and features that customers desire, it is important to generate intelligence on those preferences as early as possible. It is tempting to view AMI and modern customer information systems as uniform monoliths that will ultimately be capable of meeting virtually any need. However, constructing an integrated system is a complex affair and decisions about architecture early on may have unanticipated consequences in the longer term. In other words, it is better to know as much as possible as early as possible in order to ensure that the design is consistent with the features that customers need and desire.

Third, there is little reason to not begin generating information as early as possible. There is no scenario where developing a suite of new rate options should not involve the conducting pilots to gauge customer preferences and evaluate results. Any costs associated with such an exercise will have to be incurred sooner or later. While it is possible that some costs, such as a need to perform manual billing, might be lessened or eliminated by waiting, waiting has a cost as well in the form of foregone savings (potentially years worth) enabled by AMI.

Q. YOU PREVIOUSLY MENTIONED THAT THE COMPANY IS PARTICIPATING IN A RATE DESIGN STUDY WITH EPRI. HOW SHOULD THAT IMPACT THE DEVELOPMENT OF NEW RATE DESIGNS?

A. I expect that the EPRI study contains valuable information and I would expect it to inform the Company’s plans. Now would be the perfect time to put the results into tangible practice via rate pilots. To be clear, the precise details of the study are not known to me, but it is hard to see circumstances where the EPRI study could be a substitute for actual on the ground information specific to DEP's customers.

Q. IS THE COMPANY PURSUING ADVANCED RATE PILOTS IN OTHER JURISDICTIONS?

A. No, though DEC, DEP's sister utility, has been required to do so in North Carolina. At the conclusion of DEC's most recent North Carolina general rate case, the NCUC ordered DEC to "design and propose new rate structures to capture the full benefits of AMI".[49] The Order further required DEC to file the details of proposed dynamic rate structures within six months, in order to "allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy."[50] DEC filed a report in compliance with this Order in December 2018, but NCUC found the report non-compliant with its prior decision because among other things, the report did not contain any details of new tariffs, and the Company's proposed timeline (March 2022) for finalizing new rate designs was too long.[51]

Ultimately, the NCUC directed the DEC to file revised rate design pilot program plans and two specific rate design pilots within 60 days. One rate pilot must be applicable to residential service and one to small general service

[49] NCUC. Docket No. E-7, Sub 1146. Order dated June 22, 2018. Finding of Fact No. 39, *available at:* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

[50] *Id.* p. 124.

[51] NCUC. Docket No. E-7, Sub 1146. Order dated January 30, 2019. p. 4, *available at:* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=12af76f3-f507-4352-92ec-32facb7eaba0.

customers. A hearing on DEC's progress was held February 26^{th} and the new compliance filing is due on or around April 1^{st}.[52] It is my understanding that Company Witness Wheeler was one of DEC's witness at the February 26^{th} hearing.

Q. GIVEN THESE CIRCUMSTANCES, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION REGARDING ADVANCED RATE DESIGN DEPLOYMENT IN SOUTH CAROLINA?

A. First, the Commission should direct DEP to file a detailed AMI-enabled rate design plan within 60 days of a decision. While this timeline is short, it is not unreasonable. DEC's North Carolina filings will already have been completed by the time the Commission issues a decision in this proceeding. DEP will already have a roadmap from which to work. Second, it would also be reasonable for the Commission to direct DEP to file AMI-enable rate pilot proposals for residential and small general service customers no later than six months after a decision, and allow for a stakeholder review process on that filing. DEP is targeting the completion of AMI deployment by early 2020, so a six-month deadline for pilot rate proposals should be sufficient allow the pilots to be finalized by the time AMI deployment has been completed.

I also strongly encourage the Commission to seek to align future timelines with any it elects to establish for DEC. An integrated approach for AMI-enabled rate design would be more efficient than disconnected efforts and would promote fairness and equity throughout Duke Energy's South Carolina service territories.

[52] *Id.* p. 4 and p. 6.

Company Witness Wheeler's participation in the February 26^{th} North Carolina hearing on behalf of DEC indicates that he is Duke Energy's primary expert advanced rate design for both the DEP and DEC subsidiaries. His position as such would facilitate and support an integrated effort.

V. GRID IMPROVEMENT PLAN COST ALLOCATION AND RATE DESIGN

Q. PLEASE BRIEFLY SUMMARIZE THE NATURE OF INVESTMENTS DEP SEEKS TO UNDERTAKE AS PART OF ITS GRID IMPROVEMENT PLAN.

A. Broadly speaking, the Grid Improvement Plan investments are a collection of transmission and distribution system investments targeted at addressing "Megatrends" impacting grid operations, incremental to and "above and beyond the Company's base-level T&D plan".[53]

Q. HOW DOES DEP PROPOSE TO RECOVER THE COSTS OF MAKING THESE INVESTMENTS?

A. The Company proposes to establish a special Grid Improvement Plan tariff rider for two phases of the plan, where Phase 1 begins June 1, 2020 and Phase 2 begins June 1, 2021 with incrementally higher charges than for Phase 1. The rates in the proposed tariff are composed of an incremental monthly fixed charge and an incremental volumetric charge. For the residential class the proposed charges are as follows:

- Phase 1: \$0.74/month and \$0.00085/kWh

[53] Direct Testimony of Jay Oliver ("Oliver Direct"), p. 28, line 12.

- Phase 2: \$0.86/month and \$0.00096/kWh[54]

Q. HOW ARE THESE CHARGES DERIVED?

A. The derivation of the class allocators and the rates themselves stem from the Company's cost of service study, inclusive of the effects of the Minimum System Method of assigning costs associated with the shared distribution system. The revenue for the fixed charge portion is based on the percentage of distribution plant classified as customer-related in the Company's cost of service study. This has two effects. First, because a large portion of investments is distribution-related, the residential class is allocated a disproportionate share of the costs, 62.1% for Phase 1 and 63% for Phase 2.[55] This allocation is well in excess of the Schedule RES share of the Company's proposed total base revenue requirement, which is only 41.7%.[56]

Second, the charges for the residential class are weighted far more heavily towards the fixed monthly charge component than they are for other classes composed of customers with higher loads. For residential customers the fixed component comprises 39.7% of total revenue for Phase 1 and 40.5% for Phase 2. By comparison, for Phase 1 the fixed component for the large general service class comprises only 0.7% of the revenue requirement.[57]

[54] Wheeler Direct, Exhibit No. 6.
[55] Calculations based on Wheeler Direct, Exhibit No. 6.
[56] Calculation based on Bateman Direct, Exhibit No. 2.
[57] Calculations based on Wheeler Direct, Exhibit No. 6.

Q. CAN THESE THE CHARGES BE EXPECTED TO INCREASE BEYOND THE TIME HORIZON OF PHASE 2 OF THE GRID IMPROVEMENT PLAN?

A. Yes. The Company has forecasted that by Phase 5 (2023), the total residential allocation of Grid Improvement Plan costs is expected to exceed \$10.7 million, of which the customer-related portion is roughly \$6.4 million.[58] Extrapolating from the Phase 2 charge of \$0.86/month based on a revenue requirement of \$1,476,391, the fixed charge portion for Phase 5 would be \$3.73/month. Even if one were to assume that the number of residential customers would grow by 10% by 2023, the fixed charge portion would still be \$3.39/month. This considerable increase is beyond any increase that would be caused by base investments over the same time frame.

Q. WHAT ARE YOUR GENERAL CONCERNS ABOUT THE COMPANY'S GRID IMPROVEMENT PLAN?

A. My first concern is that while the residential class would pay for most of the costs associated with the plan, it is not clear that it would receive an equivalent share of the benefits. Given the significance of the cost burden on residential customers it is only reasonable that the Company identify at a granular project or asset-based level to whom the benefits will accrue. I have seen no analysis of this variety in the materials the Company has provided in its application.

My second concern is how the proposed rate design is affected by the Company's use of the Minimum System Method in its cost of service study. As I

[58] DEP response to VS 1-66, Attachment "Vote Solar DR 1-66 – DEP Grid Impacts Revenue Requirement", attached in Exhibit JRB-2, p. 18.

have previously discussed at length, the Minimum System Method is not a valid or accurate method for cost allocation or rate design and should be disregarded by the Commission. Furthermore, since the investments and costs associated with the Grid Improvement Plan are characterized as incremental to "base-level" investments it is difficult to grasp how they could be considered integral to, and included as part of, a so-called minimum system. Investments and costs beyond the normal course of business are by their very nature not investments in a minimally capable system and I have not identified any Grid Improvement Plan costs that are truly customer-related in nature.

Q. BEYOND THE APPLICABILITY OF THE MINIMUM SYSTEM METHOD TO ANY GRID IMPROVEMENT PLAN COSTS, DO YOU HAVE ANY OTHER CONCERNS ABOUT THE COMPANY'S PROPOSED RATE DESIGN?

A. Yes. The Company's derivation of the customer-related percentage of distribution costs is incorrect. As I previously noted, that percentage is calculated using the percentage of total distribution plant that is classified as customer-related in the Company's cost of service study. For Schedule RES customers, that amount is 64.09%, resulting in 64.09% of Grid Improvement Plan distribution investments being classified as customer-related and therefore incorporated into the fixed monthly charge.

This calculation is erroneous because the 64.09% figure includes costs associated with meters and service drops while none of the Grid Improvement Plan investments relate to these types of equipment. Even if one accepts the

Minimum System Method as valid for use in rate design for the Grid Improvement Plan, including meter and service drop costs in calculating the customer-related percentage is in error. A correct calculation removes these costs from both the numerator and denominator. For the RES class, that reduces the customer-related portion from the Company's 64.09% to the correct amount of 58.71%, the class percentage of customer-related distribution costs excluding costs with no relation to Grid Improvement Plan investments.[59] A corrected derivation is shown in Table 4.

Table 4: RES Grid Improvement Customer Allocator

DEP Fixed Charge Derivation		
RES Total Dist.	$474,863,583	
RES Customer Dist. Total	$304,355,178	
RES % Customer for GIP	64.09%	
Corrected Fixed Charge Derivation		
RES Total Dist., Adjusted	$412,955,810	No meters or services
RES Customer Dist., Adjusted	$242,447,405	No meters or services
RES % Customer for GIP	**58.71%**	

Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE TO ADDRESS THESE CONCERNS?

A. I recommend that the Commission take several actions to the extent that allows the Company to move forward on any aspects of the Grid Improvement Plan, as follows:

1. Direct DEP to perform cost-benefit evaluations that address the relative customer class distribution of costs and benefits at the project level, and align

[59] Derived using data in DEP response to VS 1-13, Attachment "DEP ORS DR 1-11 Filed SC 1 CP 2017 Adj COS Prop", attached in Exhibit JRB-2, p. 10.

the allocation of costs for the Grid Improvement Plan with the results of the class-level cost-benefit evaluations.

2. Make a finding that no Grid Improvement Plan costs can be considered to be costs associated with a minimum distribution system, even if the Commission allows the use of the Minimum System Method for other purposes.
3. Direct DEP to perform a granular examination of the costs of any Grid Improvement Plan projects that move forward to identify what portion of those costs are energy- and demand-related.
4. Direct that the rate structure for recovery of any costs associated with the Grid Improvement Plan be aligned with how those costs would be recovered according to their energy- or demand-related characteristics.
5. If the Commission approves the Grid Improvement Plan and the Company's proposed allocation and rate design generally, direct the Company to revise the customer-related percentage calculation to fully exclude distribution plant associated with meters and service drops.

VI. RATE STRUCTURE FOR RIDER EDIT-1

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RIDER EDIT-1 AND ITS PURPOSE.

A. Rider EDIT-1 is a mechanism for refunding to customers the excess money that the Company has collected for net deferred tax liabilities, stemming from a change in federal corporate income tax rate from 35 percent to 21 percent and other tax law changes. The rates in Rider EDIT-1 reflect a simple division of the excess revenue by class divided by test year sales.[60] Thus the proposed rate, a credit, is a volumetric price in cents/kWh.

Q. HOW DOES THE COMPANY JUSTIFY THE VOLUMETRIC STRUCTURE FOR RIDER EDIT-1?

A. The Company's justification for the volumetric rate structure is not spelled out in testimony. In response to an information request, DEP stated that the volumetric design was selected for administrative simplicity and because energy determinants are more predictable than demand determinants.[61]

Q. PLEASE DESCRIBE EXCESS DEFERRED INCOME TAXES AND HOW THEY HAVE ARISEN FOR DEP?

A. Company Witness Panizza discusses the conceptual framework of deferred income tax liabilities and how an "excess" has arisen in detail.[62] At a very high level though, accumulated deferred income tax liabilities, or assets, arise because of timing differences between when income taxes are collected in rates and when those taxes are actually paid. As Witness Panizza describes, any balances eventually converge to zero over the life of the underlying cause of the deferred balance.[63] However, a change in tax laws disrupts this eventual convergence because past assumptions of future tax liabilities are no longer accurate. Such is the case with a reduction in the federal corporate income tax rate from 35 percent to 21 percent. Company Witness Panizza states that the net deferred tax liability

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[60] Wheeler Direct, Exhibit No. 7.
[61] DEP response to VS 1-46(a), attached in Exhibit JRB-2, p.16.
[62] Direct Testimony of John Panizza ("Panizza Direct"), p. 7-10
[63] *Id.* p. 9, lines 3-11.

underlying the excess is "driven overwhelmingly by accelerated and bonus depreciation of fixed assets for tax purposes.[64]

Q. HOW ARE ACCUMULATED DEFERRED INCOME TAXES ("ADIT") ADDRESSED IN THE COMPANY'S COST OF SERVICE STUDY?

A. The class allocation for Rider EDIT-1 is based on an ADIT allocator, linking to the fact that EDIT amounts arise from amounts previously part of ADIT.[65] This factor is derived from the sum of individual ADIT line items, of which only roughly 2.9% is specifically identified as energy-related.[66] This is not surprising given Company Witness Panizza's statement that deferred tax liabilities are driven by investments in fixed assets.

Q. CONSIDERING THE ORIGINS OF ADIT AND THE COMPANY'S TREATMENT OF IT IN ITS COST OF SERVICE STUDY, IS A VOLUMETRIC RATE APPROPRIATE FOR RIDER EDIT-1?

A. No. The origins of the excess deferred income taxes giving rise to Rider EDIT-1 bear little relationship to energy-related functions.

Q. WHAT WOULD BE AN APPROPRIATE STRUCTURE FOR RIDER EDIT-1, TO THE EXTENT IT IS APPROVED BY THE COMMISSION?

A. A percentage of bill-based design would create a better tie between rates and the underlying cost structure and preserve the rate structure that the Commission ultimately adopts for base retail rates in the function of the rider. In other words, the rate design that the Commission determines to be reasonable for base rates

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[64] *Id.* p. 7, lines 10-11.
[65] Hager Direct, p. 17, lines 4-10.
[66] DEP response to VS 1-13, Attachment "DEP ORS DR 1-11 Filed SC 1 CP 2017 Adj COS Prop", attached in Exhibit JRB-2, p. 10.

would automatically be reflected in bill credits to customers. Customers that pay a large portion of their rates in the form of demand charges would receive effective demand rate reductions while effective customer charges and energy charges would be modified in the same manner. This type of rate structure is no more administratively complicated and no less predictable than a credit based on an energy-only bill determinant.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE TOPIC OF THE RESIDENTIAL BASIC FACILITIES CHARGE.

A. My recommendations on the establishment of the basic facilities charge are as follows:

1. The Commission should reject the changes the Company has made to its cost of service study and re-affirm precedent by directing the Company to eliminate the use of the Minimum System Method from its cost of service study.
2. The Commission should make a determination that the Basic Customer Method, which defines customer-related costs as those directly attributable to a customer's service connection, metering, billing, and customer service, is the appropriate method for classifying customer-related costs.

3. The Commission should reject the Company's proposed residential basic facilities charge and instead let it remain at its current rate of $9.06/month, which is a reasonable approximation of customer-related costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON AMI-ENABLED RATES, THE GRID MODERNIZATION PLAN, AND RIDER EDIT-1.

A. My recommendations on these topics are as follows:

1. <u>AMI-Enabled Rate Design</u>: The Commission should direct DEP to file a detailed AMI-enabled rate design plan within 60 days of a decision, and file two pilot rate proposals, one for residential customers and one for small non-residential customers, within six months of a decision. The Commission should also seek align the implementation of AMI-enabled rate designs in DEP's service territory with efforts undertaken by DEC as part of an integrated process in order to support fairness and administrative efficiency.
2. <u>Grid Modernization Plan</u>: The Commission should take several actions to ensure that the costs and benefits of the Company's Grid Improvement Plan are distributed equitably and are consistent with cost causation:
   a. Make a finding that Grid Improvement Plan investments cannot be considered part of a standard minimum distribution system because by their very nature they are extraordinary in character, regardless of whether the Commission accepts the use of the Minimum System Method in the Company's cost of service study.

b. If the Commission approves the Grid Improvement Plan and the Company's proposed allocation and rate design generally, direct the Company to revise the customer-related percentage calculation to fully exclude distribution plant associated with meters and service drops.

c. Direct DEP to perform cost-benefit evaluations that address the relative customer class distribution of costs and benefits at the project level, and align the allocation and recovery of costs with the results of the class-level cost-benefit evaluations and proper identification of energy and demand costs.

3. Rider EDIT-1: If the Commission approves Rider EDIT-1, the rate design should be revised to a percentage of bill-based mechanism in order to align it with the underlying causes of excess deferred income taxes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE
PUBLIS SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2018-318-E

IN THE MATTER OF:	)	
	)	
Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs	)	**VERIFICATION OF TESTIMONY FOR JUSTIN R. BARNES**
	)	
	)	
	)	

I, Justin R. Barnes, first being duly sworn, say that I am employed as Director of Research at EQ Research, LLC and have read my pre-filed *Direct Testimony and Exhibits* dated March 4, 2019 and *Surrebuttal Testimony and Exhibits* dated March 23, 2019, and know the contents thereof; and that the contents are true, accurate, and correct to the best of my knowledge, information, and belief.

Justin R. Barnes

Subscribed and sworn to me this the 5th day of April, 2019.

State of Virginia

County of Wise

(SEAL)

Notary Public

My Commission expires 05/31/2022.

AMANDA BROOKE DANNHARDT
NOTARY PUBLIC
REG. #7796131
MY COMMISSION EXPIRES 05/31/2022
COMMONWEALTH OF VIRGINIA

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager*,* March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource DER value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst*,* September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
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TESTIMONY

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs.

non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Hager Testimony
Date of Request: January 22, 2019
Date of Response: February 1, 2019

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The attached response to First Data Request #1-2, was provided to me by the following individual: Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, Rate Case Planning & Execution, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-2 Please refer to Hager Direct p. 14, lines 16-19.
(a) Does the Company's Minimum System Study consider the distribution assets needed if every customer had "some minimum level of usage" to be composed of: (1) the smallest equipment the Company customarily installs, (2) the smallest equipment present on its system, (3) the smallest size equipment currently available in the market currently, or (4) some other benchmark.
(b) If your response to (a) is "some other benchmark", please explain how the minimum sized equipment is determined in detail.
(c) Please explain in detail the Company's justification for its selection of minimum size system components for use in its Minimum System Study.
(d) Please state whether Witness Hager is aware of any other Duke affiliates that perform Minimum System Studies using a different methodology, and if so, explain why the method Duke Energy Progress is employing for the purpose of its cost of service study in this application is more suitable.

Response:

In response to (a), the Company's Minimum System Study is based on the smallest equipment the Company customarily installs.

In response to (b), N/A.

In response to (c), this method is most appropriate because it takes into consideration the Company's actual practices and system and is most consistent with the description of the minimum size method in the NARUC Cost of Service Manual (page 91).

In response to (d), Witness Hager is not aware of any other Duke affiliates that perform Minimum System Studies using a different methodology.

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Rate Design
Date of Request: January 22, 2019
Date of Response: February 1, 2019

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The attached response to First Data Request #1-7, was provided to me by the following individual: Steven B. Wheeler, Rates & Regulatory Strategy Director, Pricing, Load Analysis & Regulatory Solutions, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-7 Please refer to Wheeler Direct Exhibit No. 5.
(a) For Schedule RES (p. 1), please identify the number of customers that fell within each monthly energy usage band based on average monthly energy use during the test year. For example, XXXX customers had average energy use of 0 – 100 kWh per month. In your response, please separately identify the number of customers:
i. With on-site solar generation
ii. Without on-site solar generation
(b) For Schedule R-TOUD (p. 1) Please identify the number of customers that fell within each monthly energy usage benchmark based on average monthly energy use during the test year. For example XXXX customers had average energy use from 0 – 100 kWh per month.
i. With on-site solar generation
ii. Without on-site solar generation

Response:

Residential annual customer bills by usage block was provided in response to ORS AIR 1-14 (see attached file: "Annual AIR 1-14 DEP SC Blocking_Jan2017-Dec2017.xlsx"). This information is provided at a greater level of detail than used for the sample bills provided in Exhibit 5. Blocking information isn't readily available for customers with and without solar generation.

[Annual AIR 1-14 DEP SC Blocking_Jan2017-Dec2017.xlsx]

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Bateman Testimony
Date of Request: January 22, 2019
Date of Response: February 1, 2019

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The attached response to First Data Request #1-8, was provided to me by the following individual: Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, Rate Case Planning & Execution, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-8 Please refer to Bateman Direct Exhibit No. 2. Please provide an alternative version of this exhibit depicting the results of the cost of service study using the Basic Customer method rather than the Minimum System method, in which 100% of the costs recorded in FERC Accounts 364 though 368 are classified as demand related.

Response:

The attached "*DEP VS DR 1-8 Bateman 2 No Min.xlsx*" contains the requested version of Bateman exhibit 2, spreading the proposed revenue increase across South Carolina retail customer classes based on a cost of service without the minimum system approach to allocating distribution plant.

This reflects the Basic Customer Method as described in the Direct Testimony of Janice Hager, with the exception that all transformer plant in account 368 not assigned to extra facilities is allocated wholly at non- coincident peak demand. While DE Progress did allocate a portion of transformer plant as the customer-related portion of distribution plant in its prior rate case in Docket No. 2016-227-E, it has removed that assumption for purposes of this "No Minimum System" analysis.

[DEP VS DR 1-8 Bateman 2 No Min.xlsx]

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Rate Design
Date of Request: January 22, 2019
Date of Response: February 1, 2019

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The attached response to First Data Request #1-12, was provided to me by the following individual: Steven B. Wheeler, Rates & Regulatory Strategy Director, Pricing, Load Analysis & Regulatory Solutions, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-12 Please provide any analysis that the Company has performed for the purpose of evaluating the bill impact of the Company's proposed residential customer charge increases on:
(a) Low-income customers.
(b) Customers in each class with on-site generation participating in the net energy metering schedule.

Response:

The Company's review of rate impacts considers various levels of consumption, but does not separately consider customer attributes such as income level or net metering participation.

Recovering fixed costs via a kwh charge has the following detrimental consequences: 1) high usage customers subsidize low usage customers; 2) low use customers do not pay the full cost of the utility plant installed to serve them; and 3) does not provide an accurate price signal regarding the Company's costs upon which customers can make economic decisions to make investments that reduce kWh consumption.

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Hager Testimony
Date of Request: January 22, 2019
Date of Response: February 1, 2019

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The attached response to First Data Request #1-13, was provided to me by the following individual: Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, Rate Case Planning & Execution, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-13 On page 5 of Witness Hager's testimony, Hager testifies that she "[has] reviewed DE Progress' cost of service studies that were prepared and used in the rate design in this case."
(a) Please provide electronic spreadsheet versions, with all cell formulas and fill linkages intact, of all "DE Progress' cost of service studies that were prepared and used in the rate design in this case."
(b) Please provide electronic copies of all spreadsheet files linked to the requested electronic spreadsheets.

Response:

In response to (a), this information has been provided in the following data requests:

DEP ORS AIR 1-9 - Per Book Cost of Service Study
DEP ORS DR 1-9 Filed SC 1 CP 2017 PB COS.xls

DEP ORS AIR 1-10 – Present Rates Annualized Cost of Service Study
DEP ORS DR 1-10 Filed SC 1 CP 2017 Adj COS.xls

DEP ORS AIR 1-11 – Proposed Rates Cost of Service Study
DEP ORS DR 1-11 Filed SC 1 CP 2017 Adj COS Prop.xls

DEP ORS AIR 1-17 – Present Rates Annualized Unbundled Cost of Service Study
DEP ORS DR 1-17 Unbundled 2017 DEP SC 1CP Adj COS

In response to (b), there are no spreadsheet files linked to the requested electronic spreadsheets in (a).

[DEP ORS DR 1-9 Filed SC 1 CP 2017 PB COS.xls]

[DEP ORS DR 1-10 Filed SC 1 CP 2017 Adj COS.xls]

[DEP ORS DR 1-11 Filed SC 1 CP 2017 Adj COS Prop.xls]

[DEP ORS DR 1-17 Unbundled 2017 DEP SC 1CP Adj COS.xls]

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Hager Testimony
Date of Request: January 22, 2019
Date of Response: February 1, 2019

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The attached response to First Data Request #1-20, was provided to me by the following individual: Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, Rate Case Planning & Execution, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-20 On page 16 of Witness Hager's testimony, she testifies that "Witness Wheeler relied upon costs allocated as being customer-related in the Cost of Service Study in developing his recommendation regarding the Basic Facilities Charge."
(a) Please provide an electronic spreadsheet version, with all cell formulas and file linkages intact, of the unit cost study relied on by Company witness Steven B. Wheeler to develop his recommendation regarding the residential Basic Facilities Charge.
(b) Please provide an electronic spreadsheet version, with all cell formulas and file linkages intact, of the unit cost study associated with a version of the Company's cost of service study which classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., relies on the Basic Customer method to classify distribution plant costs.)

Response:

In response to (a), please see attached file "*Vote Solar DR 1-23 - DEP Unit Cost Study.xlsx*" which shows the unit cost study relied on by Company Witness Steven B. Wheeler to develop his recommendation regarding the residential Basic Facilities Charge. This file is also provided in response to DR 1-23 with this data request.

In response to (b), please see attached file "*ORS AIR 13-4 Wheeler Exhibit 2 wo Min System.xlsx*" which shows the unit cost study associated with a version of the Company's cost of service study which classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related.

[Vote Solar DR 1-23 - DEP Unit Cost Study.xlsx]

[ORS AIR 13-4 Wheeler Exhibit 2 wo Min System.xlsx]

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Rate Design
Date of Request: January 22, 2019
Date of Response: February 1, 2019

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

The attached response to First Data Request #1-36, was provided to me by the following individual: Steven B. Wheeler, Rates & Regulatory Strategy Director, Pricing, Load Analysis & Regulatory Solutions, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-36 Please provide the following information regarding the Company's net metering customers as of the time of filing this application:
(a) Total number of net metering customers (all classes);
(b) Number of net metering customers per rate schedule;
(c) Aggregate capacity of net metering facilities on each rate schedule;
(d) Average per customer billed usage (kWh) for residential net metering customers during each month of the test period (i.e., the average net purchase by net metering customers after energy exports to the grid from the customer-generator have been subtracted or netted from gross imports from the grid);
(e) Average per customer maximum demand (kW) (15-minute or hourly) during each month of the test period, if available.

Response:

The number of South Carolina net metering customers by rate schedule with the installed nameplate capacity of generation as of October 2018 is provided in the attached file (See attached file: "Vote Solar DR 1-36 – DEP Net Metering Statistics"). Monthly billed usage is not readily available for net metering customers alone; however, SC residential net metering customer annual usage for the year ended December 31, 2017, is provided in the attached file. Demand information for net metering customers is not readily available since it isn't maintained in the billing system for schedules without demand rates.

[Vote Solar DR 1-36 – DEP Net Metering Statistics]

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Rate Design
Date of Request: January 22, 2019
Date of Response: February 1, 2019

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

The attached response to First Data Request #1-46, was provided to me by the following individual: Steven B. Wheeler, Rates & Regulatory Strategy Director, Pricing, Load Analysis & Regulatory Solutions, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-46 Please refer to Wheeler Direct at p. 36, lines 3-5 describing the derivation of class rates for the Company's proposed EDIT-1 Rider.
(a) Please justify the use of a fully volumetric rider to refund excess deferred income taxes to customers, including how the proposed design is consistent with cost causation.
(b) Please confirm or deny that a portion of the accumulated deferred income taxes (ADIT) that give rise to the need for the EDIT-1 Rider are associated with utility plant investments that would be classified as customer or demand-related. If your response is to deny that this statement is true, please explain in detail.

Response:

a) As an annual adjustment rider, the use of a volumetric rate was selected for administrative ease in collecting and tracking revenues recovered in the rider. Volumetric energy rates apply to all classes allowing a uniform approach for cost recovery purposes. Energy determinants are also more predictable than demand determinants which can be significantly influenced by unusual weather events.

b) The revenue requirement sought for recovery in the EDIT rider is primarily associated with tax impacts associated with utility plant-related costs.

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Grid Rider
Date of Request: January 22, 2019
Date of Response: February 1, 2019

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

The attached response to First Data Request #1-66, was provided to me by the following individual: Steven B. Wheeler, Rates & Regulatory Strategy Director, Pricing, Load Analysis & Regulatory Solutions, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-66 Please provide all studies, analyses, memos, workpapers, or written documents of any nature regarding the impacts to ratepayers from the additional increase on monthly bills that would be caused by the proposed Rider related to the Company's Grid Improvement Plan.

Response:

Pursuant to clarification from counsel:
1) See attachment to the response to Vote Solar Data Request 1-25: "ORS AIR 1-13 Rate Design File.xlsx". The calculation can be found at cell AE7 on the "Wheeler Exh 3" worksheet.
2) See: "Vote Solar DR 1-66 – DEP Grid Impacts Revenue Requirement.xlsx"
3) See: "Vote Solar DR 1-66 –GIP Budgets and Rates.xlsx"

[Vote Solar DR 1-66 – DEP Grid Impacts Revenue Requirement.xlsx]

[Vote Solar DR 1-66 –GIP Budgets and Rates.xlsx]

BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2018-318-E

IN THE MATTER OF: Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs	))))))	**SURREBUTTAL TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF VOTE SOLAR**

March 25, 2019

TABLE OF CONTENTS

1

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. Justin R. Barnes, 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony on March 4, 2019.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSES OF YOUR SURREBUTTAL TESTMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony filed by Duke Energy Progress ("DEP" or "the Company") witnesses Janice Hager and Steven Wheeler regarding the validity of the Minimum System Method of classifying distribution system costs for the purposes of cost allocation and rate design, and the establishment of a reasonable residential basic facilities charge ("BFC"). I also respond to Company Witness Wheeler's new proposal that Schedule RES customers take service under rates with a demand component that recovers all non-minimum system distribution costs.[1]

Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?

A. In Section III I address the validity of the Minimum System Method, which forms the basis for the Company's proposed residential BFC, primarily in response to

[1] Rebuttal Testimony of Steven Wheeler ("Wheeler Rebuttal"), p. 10, lines 1-5.

Company Witness Hager. In Section IV I respond to the Company's assertions regarding proper amount of the residential BFC, and a new residential BFC proposal made by Company Witness Wheeler. In Section V I address Company Witness Wheeler's residential demand rate proposal. Section IV contains my concluding remarks and recommendations.

III. THE VALIDITY OF THE MINIMUM SYSTEM METHOD

Q. PLEASE DESCRIBE THE MINIMUM SYSTEM METHOD AND HOW DEP USES IT IN ITS COST OF SERVICE STUDY.

A. As I described in my direct testimony, the Minimum System Method postulates that some portion of the distribution system shared by all customers is customer-related and therefore allocable to customer classes based on the number of customers in a given class. In other words, a certain level of investment in the shared system would be required to connect a customer even if that customer had a minimal load. In practice, this results in a portion of costs in FERC Accounts 364-368, involving poles, overhead and underground conductors, and line transformers being classified as customer-related. Its use also has downstream effects beyond distribution cost allocation because other dynamic allocators are influenced by the results. The Company uses this method in its cost of service study to calculate class allocations and the proposed $29.00/month residential BFC.

In my direct testimony I described the methodological failings of the Minimum System Method, summarized below:

1) It relies on a flawed premise that a customer with a zero or minimal load would desire a connection to the distribution system.

2) It tends to over-allocate distribution costs to highly populous rate classes, because a minimum system is typically capable of serving a considerable amount of demand, resulting in this demand being assigned largely to the highly populous classes, which then receive a further allocation of remaining demand-related costs based on the full class demands.

Q. WHAT RECOMMENDATIONS DID YOU MAKE IN YOUR DIRECT TESTIMONY REGARDING THE USE OF THE MINIMUM SYSTEM METHOD?

A. I recommended that the Public Service Commission ("Commission") reject its use for both cost allocation and rate design, and instead rely on the Basic Customer Method to define customer-related costs. The Basic Customer Method confines customer-related costs to those associated with metering, billing and collection, customer service, and the customer's service drop.

Q. HOW DOES THE COMPANY JUSTIFY THE USE OF THE MINIMUM SYSTEM METHOD AND RESPOND TO YOUR RECOMMENDATIONS?

A. In discussing the validity of the Minimum System Method, in both direct testimony and rebuttal testimony, Company Witness Hager relies primarily on the National Association of Regulatory Commissioners Electric Utility Cost Allocation Manual ("NARUC CAM").[2] In rebuttal testimony Witness Hager also

[2] Rebuttal Testimony of Janice Hager ("Hager Rebuttal"), p. 8, line 19 through p. 9, line 8.

contends that Dr. James Bonbright, in his seminal work *Principles of Public Utility Rates*, lends support to the Minimum System Method by way of a statement that "the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs."[3] This assertion was made in response to statements in my direct testimony relating Dr. Bonbright's discussion of the matter, where he characterizes the costs of a minimum distribution system as "unallocable".[4]

Q. HOW DO YOU RESPOND THE COMPANY WITNESS HAGER'S CONTENTION THAT THE NARUC CAM SUPPORTS THE COMPANY'S USE OF THE MINIMUM SYSTEM METHOD OF CLASSIFYING DISTRIBUTION COSTS?

A. I do not disagree that the NARUC CAM does suggest that some distribution costs could be considered customer-related. However, Company Witness Hager fails to appreciate that the NARUC CAM also characterizes such a practice as the subject of an "unresolved argument" among analysts.[5] In addition, the NARUC CAM also notes that "minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."[6] Witness Hager also fails to address the fact that a subsequent NARUC-commissioned report published nearly a decade later found that more than thirty states (at the time of the report)

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[3] Hager Rebuttal, p. 8, lines 13-17.
[4] Dr. James Bonbright, *Principles of Public Utility Rates*, p. 348, Columbia University Press (1961).
[5] NARUC. Electric Utility Cost Allocation Manual. p. 136. 1991.
[6] *Id.*, p. 95.

used the Basic Customer Method of classifying distribution costs rather than the Minimum System Method.[7]

Ultimately the fact that the Basic Customer Method is not well-represented in the NARUC CAM is not indicative of its broader level of acceptance, which is higher than the acceptance of the Minimum System Method and associated variations. Earlier draft versions of the NARUC CAM and related discussions included the Basic Customer Method in addition to the Minimum System Method and Zero-Intercept Method as methodologies for classifying distribution costs. The Basic Customer Method was apparently removed from the final version, eliciting concerns by least one state regulatory agency. Surrebuttal Exhibit JRB-1 contains a letter from the Washington Utilities and Transportation Commission ("UTC") voicing the UTC's concerns about the omission of the Basic Customer Method from the NARUC CAM. Among other things, the letter notes that UTC staff believes it to be the most common approach taken by regulators throughout the country, citing the states of Arizona, Iowa, and Illinois as states that have explicitly rejected the Minimum System Method and Zero-Intercept Method.

[7] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, REGULATORY ASSISTANCE PROJECT (2000), *available at:* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

Q. HAVE OTHER STATES ALSO REJECTED THE USE OF THE MINIMUM SYSTEM METHOD OR THE MINIMUM INTERCEPT METHOD IN RECENT YEARS?

A. Yes. As I described in my direct testimony, legislators in Connecticut directed the Public Utilities Regulatory Authority ("PURA") to utilize the Basic Customer Method in 2015.[8] Likewise, in 2018 regulators in Colorado directed Black Hills Energy to eliminate the Minimum Intercept Method from its cost of service study in the utility's most recent general rate case.[9]

Q. IS COMPANY WITNESS HAGER'S CHARACTERIZATION OF BONBRIGHT'S VIEWS ON CUSTOMER COST CLASSIFICATION AN ACCURATE REPRESENTATION OF HIS THOUGHTS ON THE MATTER?

A. No. Company Witness Hager selectively truncates Dr. Bonbright's writing in a manner that distorts the meaning. First, in discussing distribution cost classification and a hypothetical minimum-sized distribution system, Dr. Bonbright states "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[10] Witness Hager relates subsequent text where Dr. Bonbright avers that minimum

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[8] Connecticut Public Act 15-5, June Special Session*, available at:* https://www.cga.ct.gov/asp/cgabillstatus/CGAbillstatus.asp?selBillType=Bill&bill_num=1502&which_year=2015

[9] Colorado Public Utilities Commission. Docket No. 17AL-0477E. Decision No. C18-0445. June 15, 2018, *available at*: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=887641

[10] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 348.

system costs ought also to be excluded from demand-related costs ("the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs."[11]). However, she fails note that Dr. Bonbright closes the loop on the matter by concluding that the costs of a minimum-sized distribution system are "strictly unallocable", while further cautioning against rendering the category of customer costs a "dumping ground" for costs that defy easy categorization.[12]

Q. WHAT ARE THE MOST APPROPRIATE CONCLUSIONS TO REACH FROM YOUR DISCUSSION OF THE NARUC CAM AND DR. BONBRIGHT'S WORK?

A. The most reasonable conclusions are: (1) the costs of a minimum-sized system are not customer-related, and (2) a majority of states recognize this by limiting the customer-related classification to the costs of meters, billing and collection, customer service, and customer service drops, and classifying 100% of the costs associated with the shared distribution system as demand-related. How to allocate those costs is apparently a matter of debate in Dr. Bonbright's thinking, but he clearly believed that a customer-related classification is inappropriate. A conclusion that the full scope of distribution costs are demand-related makes the most sense because a hypothetical minimum-sized distribution system is typically capable of supporting a sizable amount of customer demand.

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[11] Hager Rebuttal, p. 8, lines 13-17.
[12] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 348.

Q. IN LIGHT OF THE CONCERNS YOU HAVE RAISED ABOUT THE OVERALLOCATION OR DOUBLE-COUNTING OF DISTRIBUTION COSTS TO POPULOUS RATE CLASSES, IS THERE EVIDENCE INDICATING THAT THE COMPANY'S MININUM SYSTEM WOULD SUPPORT A SIGNIFICANT AMOUNT OF DEMAND?

A. Yes. Company Witness Hager voices confusion about my contention that the Minimum System Method causes to be double-counted.[13] I made this statement in my direct testimony in reference to the fact that, as the NARUC CAM observes, a minimum-sized distribution system has a load carrying capability that can be viewed as a demand-related cost. A populous class such as the residential class is allocated the bulk of these demand costs by the Minimum System Method, while also receiving an allocation of the remaining demand-costs based on full class demand. I referred to this as "double-counting", which I believe is an accurate description, though the effect could also be described as "double-allocation" or "over-allocation".

Such an effect is most easily visible in the context of line transformers. If every one of DEP's roughly 168,000 customers had a minimal demand consisting of a 100-Watt light bulb, the system load would be roughly 16.8 MW. The Company's minimum-sized system is composed of approximately 34,400 10 kVa overhead line transformers and 12,740 25 kVA underground line transformers.[14]

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[13] Hager Rebuttal, p. 15, lines 4-6.

[14] DEP response to VS 1-18, Attachment entitled "DEP VS DR 1-18 2017 Min Sys Study," Attached in Surrebuttal Exhibit JRB-2, p. 4. Numbers derived by scaling total DEP transformers by a factor of 8.9975%, the South Carolina percentage of total plant in

Thus the combined kVa rating of the "minimum-sized" system is roughly 662 MVa. Clearly, a system composed of the minimum-sized line transformers would support significant demand in excess of a scenario where each customer possesses only a minimal lighting load.

Q. DOES COMPANY WITNESS HAGER TAKE ISSUE WITH ANY OTHER PORTIONS OF YOUR DIRECT TESTIMONY THAT YOU WISH TO RESPOND TO?

A. Yes. Witness Hager states that my derivation of the costs for a grid-independent solar and battery storage system that would provide the same level of service as system capable of supporting a minimal lighting load is irrelevant because the Company's cost of service study focuses only on allocating embedded costs.[15]

Q. HOW DO YOU RESPOND TO THIS CRITICISM?

A. Company Witness Hager misses the points I am making based on this analysis. My first point, as I discuss at length in my testimony, is that the Minimum System Method is increasingly anachronistic. It rests on a hypothetical "what if" scenario (i.e., a customer with a minimal service need) that I have demonstrated would not occur in the modern day. When the central element of such a "what if" scenario is at best highly implausible, one should question the conceptual framework of the method itself.

Second, as I observed in the context of principles of utility ratemaking, when a natural monopoly such as electric distribution service is present,

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FERC Account 368 because South Carolina and North Carolina are combined in the Minimum System Study.

[15] Hager Rebuttal. p. 14, lines 11-16.

regulation should function as a substitute for competition. In this instance, the Company is seeking a residential BFC in an amount that would be uncompetitive with other options that provide the same hypothetical level of service. This also points to fundamental flaws in the methodology. Customers connect to the grid in order to receive service for their full demands. Even if they desired the minimal level of service contemplated by the Minimum System Method, they would not elect to take that service from the Company at the rates the Company proposes to charge.

IV. THE RESIDENTIAL BFC

Q. WHAT RECOMMENDATIONS DID YOU MAKE REGARDING THE SETTING OF THE RESIDENTIAL BFC IN YOUR DIRECT TESTIMONY?

A. Based on my review of the Company's calculated customer-related costs without a minimum system assumption, and certain modifications I made thereto, I derived a reasonable maximum residential BFC of $9.23/month. In the interest of simplicity and because the outputs of DEP's cost of service study do not permit a granular, examination of costs by FERC Account, I recommended that the residential BFC remain at $9.06/month.

Q. PLEASE SUMMARIZE THE COMPANY'S RESPONSES TO YOUR DIRECT TESTIMONY REGARDING THE RESIDENTIAL BFC.

A. Company Witness Wheeler contends that my recommended residential BFC would create inaccurate price signals, cause high usage customers to subsidize low usage customers, and result in low usage customers failing to pay the costs associated with serving them.[16] Company Witness Hager raises a similar concern, that moving costs from the customer classification to other classifications would result in customers such as those with summer homes or on-site solar installations not paying their "fair share of the costs of distribution facilities."[17] Further portions of Witness Wheeler's rebuttal testimony on the residential BFC:

- State that he "believes there is merit" to the concerns raised by myself and several other witnesses regarding the lack of gradualism present in the initially proposed residential BFC, and suggest a "possible" alternative approach that would result in a residential BFC of $19.03/month.[18]
- Opine that the proposed residential BFC would not disproportionately harm low-income customers.[19]

Q. HOW SHOULD THE COMMISSION VIEW THE COMPANY'S ARGUMENT THAT YOUR RESIDENTIAL BFC RECOMMENDATIONS WOULD CAUSE LOW USAGE CUSTOMERS TO BE SUBSIDIZED BY HIGH USAGE CUSTOMERS?

A. The Commission should give this argument no weight because the Company has not presented any supporting evidence or analysis. The single most basic question that must be asked when evaluating such an assertion is "What is the definition of a low usage customer?" Yet when Vote Solar asked this simple question to

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[16] Wheeler Rebuttal, p. 5, line 17 through p. 6, line 6.
[17] Hager Rebuttal, p. 6, line 18 through p. 7, line 3.
[18] Wheeler Rebuttal, p. 10, lines 6-21.
[19] *Id.*, p. 6-7.

Company Witness Hager based on similar statements contained in her direct testimony, the Company's response stated "the use of the term "low use customer" was meant to be general in nature" and was not intended to refer to any specific usage threshold.[20] Cost of service is a discipline of evidence and numbers, not broad assertions or generalizations. Statements for which the Company cannot respond to the most basic interrogatory with a substantive answer should not be considered credible.

Q. IS THERE MERIT TO COMPANY WITNESS HAGER'S ASSERTION THAT RESIDENTIAL NET METERING CUSTOMERS ARE AVOIDING PAYING THEIR "FAIR SHARE" OF SERVICE COSTS?

A. No. My own calculations there show that there is reason to believe that the value of residential net metering production, in the form of reduced allocations of costs assigned based on coincident peak contribution and the marginal time-varying value of customer-generated energy, is close to the retail rate that these customers avoid. In my direct testimony I estimated that residential net metering customers could have been expected to produce a benefit of $84,000/MW-DC to the residential class due to reductions in allocations based on coincident peak demand. Based on this estimated cost of service benefit spread across annual estimated energy production from these same systems, plus the Company's calculated marginal time-varying energy costs from its 2017 fuel cost proceeding, the value of that generation translates to roughly 9.4 cents/kWh.[21]

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[20] DEP response to VS 1-4(a). Attached in Surrebuttal Exhibit JRB-2, p. 2.

[21] Marginal avoided energy costs from Commission Docket No. 2017-1-E. Direct Testimony of George Brown. p. 7, Table 3. April 27, 2017.

While this amount is less than what net metering customers avoid paying under current rates (ranging from 10.4 – 11.4 cents/kWh under Schedule RES), it does not include distribution-level load shifting benefits or other potential avoided cost streams. Given how close these numbers are and the fact that no customer truly pays their exact cost of service, I think a generalization the net metering customers do not pay their fair share of costs is misleading.

Q. DO YOU AGREE THAT COMPANY WITNESS WHEELER'S "POSSIBLE APPROACH" TO SETTING THE RESIDENTIAL BFC IS REASONABLE?

A. No. Witness Wheeler's derivation is based on increasing the residential BFC by 50% of the difference between the current charge of $9.06/month and the Company's minimum-system derived theoretical residential BFC of $29.00/month.[22] This would result in an increase of $9.97/month, to $19.03/month. The $29.00/month amount hinges on the use of the Minimum System Method, which as I have discussed at length, should not be utilized in the Company's cost of service study. Thus the amount of the increase under this approach is biased by the inappropriate upper benchmark. My own derivation of a reasonable maximum residential BFC is $9.23/month. Even that amount may be overstated because as discussed in my direct testimony, it includes the full cost of the Customer Connect platform as customer-related, even though Customer Connect is intended to also serve energy and demand-related use cases, and it was

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[22] Wheeler Rebuttal, p. 10, lines 16-21.

not possible to fully evaluate general and administrative costs that should not be included in a customer charge.

I also disagree that such an increase is a reasonable adherence to the principle of gradualism. Such an increase would still be the largest adopted for an investor-owned utility ("IOU") in monetary terms in rate cases filed since July 2014. The next largest is a $7.69/month increase allowed for Alaska Power in October 2017. It would also more than double the current residential BFC, a percentage increase of 110%, which exceeds all other increases in percentage terms except one. That single example is for Duke Energy Kentucky, for which an increase from $4.50/month to $11.00/month (144%) was authorized in 2018. The end result for Duke Energy Kentucky result though, is far more consistent with the national average residential customer charge of $10.42/month.

Q. HOW DO YOU RESPOND TO COMPANY WITNESS WHEELER'S CONTENTION THAT RESIDENTIAL BFC INCREASES WOULD NOT DISPROPORTIONATELY HARM LOW-INCOME CUSTOMERS?

A. Witness Wheeler provided a chart purporting to illustrate that low-income customers would not be disproportionately harmed by the Company's proposed BFC, showing a wide range of average monthly usage among low-income customers ($30,000 or less in annual household income).[23] However, this chart actually appears to show the opposite, indicating that a significant majority of low-income customer bills are for usage below the residential class average. The class average generally defines the usage threshold at which a customer is

[23] Wheeler Rebuttal, p. 7.

indifferent to whether revenues are collected via a fixed monthly charge or a volumetric charge. If the percentage of low-income customers with average usage below the class average is larger than the percentage with above average usage, the proposed residential BFC would disproportionately adversely impact low-income customers because a majority are made worse off by increases in the residential BFC.

Q. IN THE HYPOTHETICAL, IF A MAJORITY OF LOW-INCOME CUSTOMERS ARE MADE BETTER OFF BY LOWER FIXED CHARGE RATES, DOES THAT NOT ALSO MEAN THAT A MINORITY WOULD BE MADE WORSE OFF?

A. It does, but high fixed charges coupled with lower usage charges are a poor solution for addressing the needs of those high usage customers. For one, in this hypothetical scenario higher fixed charges would be punitive on a group of customers that is larger than the group they help. Second, inordinately high usage can be addressed through targeted energy efficiency initiatives. Such a strategy can produce outcomes that leave all customers better off, rather than just helping some at the expense of others.

V. DEMAND CHARGES FOR RESIDENTIAL CUSTOMERS

Q. PLEASE SUMMARIZE COMPANY WITNESS WHEELER'S PROPOSAL TO ESTABLISH A DEMAND CHARGE FOR SCHEDULE RES CUSTOMERS.

A. Witness Wheeler's proposal is only vaguely defined, stating that the Company should revise Schedule RES to establish a demand component that recovers all distribution costs not reflected as customer-related by the Minimum System Method. The basis for this proposal is Mr. Wheeler's opinion that cost causation is best served by recovering demand-related costs through demand charges. [24]

Q. DO ANY OTHER IOUS IN THE COUNTRY INCLUDE DEMAND CHARGES UNDER STANDARD OR MANDATORY RESIDENTIAL RATE SCHEDULES?

A. No. I have researched this topic exhaustively and demand charges within standard residential rates are not present for any IOU. A number of utilities offer optional residential demand rates, including DEP, but none make them mandatory for an entire residential class as the Company proposes.

Q. ARE DEMAND CHARGES CONSISTENT WITH COST CAUSATION FOR RESIDENTIAL CUSTOMERS?

A. It is necessary to speak in generalities here because the details of the Company's proposal are sparse. That said, as typically practiced in the form of charges based on monthly non-coincident peak demand, they are not aligned with cost causation. Demand-related costs are caused by customer contributions to peaks at different

[24] Wheeler Rebuttal, p. 10, lines 1-5.

levels of the system. A non-coincident demand charge does not reflect the time-varying nature of demand that causes these costs, or load diversity.[25] For customers with consistent loads that tend to correspond to peak times, the inaccuracies may be tolerable. Such is not true for the residential class, as individual customer loads tend to be highly variable over the course of a day, month, or season. Furthermore, demand charges are blunt instruments that fail to capture how much a customer contributes *on average* to the peaks that drive costs, since billing demand is typically measured at time scales ranging from 15 minutes to an hour.

Q. DO RESIDENTIAL CUSTOMERS CURRENTLY PAY FOR THE COSTS ASSOCIATED WITH THE DEMAND THEY PLACE ON THE DISTRIBUTION SYSTEM?

A. Yes, they simply do so based on their average demands because volumetric rates effectively spread demand-related costs across all hours, or in the case of time-varying rates, the hours that correspond to peak and off-peak periods.

Q. BEYOND COST CAUSATION, ARE THERE OTHER REASONS THAT MANDATORY DEMAND RATE DESIGNS ARE NOT USED IN RESIDENTIAL RATES?

A. Yes. There is a general acknowledgement that for residential customers, demand rates effectively act as a fixed charge because most residential customers are relatively unsophisticated and do not understand them. Moreover, even if

[25] Load diversity refers to the fact that the sum of non-coincident peak loads of a group of individual customers is less than the maximum load that the same group of customers places on the system because the individual customer peak loads occur at different times.

customers do possess a conceptual understanding, it is likely that the vast majority do not have the ability manage their demands in the same way that a larger, more sophisticated customers can.

Q. WOULD THE COMPANY'S PROPOSAL LEAD TO A MORE ECONOMICALLY EFFICIENT RATE STRUCTURE FOR RESIDENTIAL CUSTOMERS?

A. No. Economic efficiency is achieved by sending an accurate price signal that customers are equipped to respond to. As I discuss above, as traditionally implemented, demand charges are not consistent with cost causation for residential customers, thus the price signal is not accurate. Second, rates only produce more economically efficient outcomes if customers can respond to them. If customers cannot respond, a new price signal just creates a different set of winners and losers without increasing economic efficiency.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING WITNESS WHEELER'S RESIDENTIAL DEMAND CHARGE PROPOSAL?

A. The Commission should reject the proposal. As a threshold matter, it would be inappropriate to consider a new proposal that contemplates dramatic changes to residential rate structure at this stage of the proceeding. Furthermore, the proposal itself is ill-defined and lacks anything resembling the level of detail and evidentiary support necessary to determine whether it would produce just and reasonable rates and achieve the proper balance of ratemaking objectives.

VI. CONCLUSION

Q. DOES ANY INFORMATION PROVIDED BY THE COMPANY IN ITS REBUTTAL CHANGE ANY OF THE RECOMMENDATIONS YOU MADE IN YOUR DIRECT TESTIMONY?

A. No, my initial recommendations are unchanged. However, I additionally recommend that the Commission disregard Company Witness Wheeler's proposal to establish a demand charge for Schedule RES customers. Beyond the fact that it would be inappropriate to consider such a significant new rate design proposal at this stage of the proceeding, the proposal itself is unprecedented and vaguely defined, and the Company has not provided any substantive analysis of why it is needed and how it would impact customers.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

Found in Box 27

(?)

STATE OF WASHINGTON

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

P.O. Box 9022 • 1300 S. Evergreen Park Dr. S.W. • Olympia, Washington 98504-9022 • (206) 753-6423 • (SCAN) 234-6423

REF:6-1132

June 11, 1992

Mr. Julian Ajello
California PUC
505 Van Ness Avenue
San Francisco, California 94102

Dear Mr. Ajello:

Please accept this belated response to your request for review of the February, 1991 draft of the new NARUC Electric Utility Cost Allocation Manual. Our staff recognizes that the final has now been printed. However, the inconsistent treatment of customer related costs in the manual is of concern. In three areas, three different approaches are presented. The first is an energy weighted approach, the second the so-called "minimum-system" or "zero-intercept" method, and the last is the "basic customer" method.

At page 39 of the draft, distribution plant is identified as being customer, demand, and energy-related. That is consistent with the treatment of gas distribution plant by this Commission, where it has ordered that 50% of distribution mains be treated as commodity-related. Our Commission has not made specific findings on electric distribution plant, except as set forth below.

At pages 91-100 of the draft, the minimum-system and zero intercept methods are presented. These methods do not conform to the matrix on page 39, which incorporates an energy component of distribution plant. Unfortunately, these two methods are the only methods presented. These are the two methods our Commission has explicitly rejected.

Finally, at page 148, in the section on marginal cost determination, the "basic customer" method, counting as customer related costs only meters, services, meter reading, and billing, is identified and defended.

Previous drafts included additional methods which are missing from the final version. For example, the 10/31/88 draft discussed at the fall meeting in San Francisco contained a section explicitly setting forth the basic customer method in the embedded cost section. In November of 1988, a section discussing the energy-weighted method was distributed to the Committee.

Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" and "minimum-intercept" methods are not acceptable, and that the only costs which should be considered customer-related are the costs of meters, services, meter reading and billing. Our staff believes that is the most common approach taken by Commissions around the country. For example, in Iowa, the administrative rules of the Commission set this forth explicitly, while in Arizona and Illinois, the Commissions have explicitly rejected the minimum-system or minimum-intercept methods in favor of the basic customer approach.

In gas cost of service, our Commission has explicitly found that distribution plant (including service connections) is partially demand-related and partially commodity related, consistent with the matrix on page 39. The corresponding plant on the electric side -- poles, conductors and transformers -- has not been positively resolved in any cases to date. A recently filed electric cost of service case will provide an opportunity for advocates of the demand-only allocation approach and those favoring an energy weighing approach to make their cases before the Commission.

We hope that it is possible to either correct future editions of the Manual to reflect the variety of approaches to determining customer-related costs, or to even issue a correction to this edition.

Please feel free to contact Bruce Folsom at (206) 586-1132 with any questions you may have.

Sincerely,

Paul Curl

Paul Curl
Secretary

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Hager Testimony
Date of Request: January 22, 2019
Date of Response: February 1, 2019

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

The attached response to First Data Request #1-4, was provided to me by the following individual: Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, Rate Case Planning & Execution, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-4 Please refer to Hager Direct, p. 15, lines 16-19.
(a) Please define the term "low use customer".
(b) Please provide any analysis the Company has conducted supporting this definition and the associated workpapers in electronic spreadsheet format with all formulas and linkages intact.

Response:

In response to (a), Witness Hager's use of the term "low use customer" was meant to be general in nature. Witness Hager did not intend to imply that there were specific usage thresholds associated with this term.

In response to (b), the Company has no analysis to support a specific definition.

Duke Energy Progress' Response to
Vote Solar's First Set of Written Discovery Request
Pursuant to S.C. Code Ann. § 58-4-55
Docket No. 2018-318-E
Related to Hager Testimony
Date of Request: January 22, 2019
Date of Response: February 1, 2019

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

The attached response to First Data Request #1-18, was provided to me by the following individual: Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, Rate Case Planning & Execution, and was provided to Vote Solar under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Progress, LLC

DUKE ENERGY PROGRESS

Request:

1-18 On page 12 of Witness Hager's testimony, she testifies that "the Company has also identified a portion of the costs for distribution lines and poles … that are customer-related."

(a) Please provide complete and detailed documentation of the input data, methods, and results of the Minimum System analyses used to determine the customer-related components of the Company's investments in:

i. Primary poles.
ii. Secondary poles.
iii. Primary overhead conductors.
iv. Secondary overhead conductors.
v. Primary underground lines.
vi. Secondary underground lines.
vii. Line transformers.

(b) Please provide copies of all workpapers, including electronic spreadsheets with cell formulas and file linkages intact, relied on to derive the customer-related portion of costs recorded in FERC Accounts 364-368.

Response:

In response to (a), please find attached the "*DEP VS DR 1-18 2017 Min Sys Study.xlsx*" file which contains the analysis for the minimum system portion or customer related percentage of distribution plant by FERC accounts 364 – 368. The "B - Min System Calc" worksheet provides the final calculations supporting these customer vs. demand percentages for each of those FERC accounts.

In response to (b), the "WK 2-8" worksheet in the "*ORS Rates DR 4-1 INPUT PLANT 2017.xlsx*" file attached, applies the percentages from this minimum system study (provided with 1-18(a)), to the SC retail portions of distribution plant balances to derive the customer vs. demand related portion of each of these FERC distribution plant accounts. These percentages are applied across both primary and secondary portions of the FERC accounts, where applicable.

[DEP VS DR 1-18 2017 Min Sys Study.xlsx]

[ORS Rates DR 4-1 INPUT PLANT 2017.xlsx]