STATE OF NORTH CAROLINA
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
	)	
Duke Energy Progress, LLC's Application	)	**Docket No. E-2, Sub 1219**
to Adjust Retail Rates, Request for an	)	
Accounting Order and to Consolidate	)	
Dockets	)	

DIRECT TESTIMONY AND EXHIBITS OF

JONATHAN F. WALLACH

ON BEHALF OF

**THE NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL, AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY**

April 13, 2020

TABLE OF CONTENTS

EXHIBITS

JFW-1 – Resume of Jonathan F. Wallach, Resource Insight, Inc.

JFW-2 – George J. Sterzinger, *The Customer Charge and Problems of Double Allocation of Costs*, PUBLIC UTILITIES FORTNIGHTLY 30–32 (1981).

JFW-3 – Duke Energy Progress Second Supplemental Response to NCJC Data Request 4-16, Docket No. E-2, Sub 1219, March 16, 2020.

JFW-4 – Duke Energy Indiana, LLC Response to Citizens Action Coalition Data Request 12-4, IURC Cause No. 45253, September 23, 2019.

JFW-5 – Duke Energy Progress Response to NCJC Data Request 4-5, Docket No. E-2, Sub 1219, February 10, 2020.

JFW-6 – Duke Energy Progress Revised Response to Public Staff Data Request Item No. 60-15, Docket No. E-2, Sub 1219, February 10, 2020.

JFW-7 – Citations to Marginal-Price Elasticity Studies

JFW-8 – Duke Energy Progress Response to NCJC Data Request 4-1, Docket No. E-2, Sub 1219, February 10, 2020.

JFW-9 – Letter from Paul Curl, Secretary of Washington Utilities and Transportation Commission, to Julian Ajello of the California Public Utility Commission, regarding review of the NARUC Electric Utility Cost Allocation Manual, June 11, 1992.

I. INTRODUCTION AND SUMMARY

Q: PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A: I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?

A: Yes. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the United States and Canada, including before this Commission in the previous general rate cases for Duke Energy Carolinas (Docket No. E-7, Sub 1146) and for Duke Energy Progress (Docket No. E-2, Sub

1142). I also testified in the most recent Duke Energy Carolinas and Duke Energy Progress rate cases in South Carolina and in the most recent Duke Energy Indiana rate case. In addition, I submitted testimony in the pending Duke Energy Carolinas general rate case (Docket No. E-7, Sub 1214). I include a detailed list of my previous testimony in Exhibit JFW-1.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: On October 30, 2019, Duke Energy Progress, LLC ("DEP" or "the Company") filed an application and supporting testimony for approval of increased electric rates and charges. My testimony responds to the testimony by Company witnesses:

- Michael J. Pirro, regarding the Company's proposals to: (1) allocate among the various retail rate classes the requested base revenue increase; and (2) maintain the monthly Basic Customer Charge ("BCC") for residential customers at its current rate.[1]
- Janice Hager, regarding the Company's cost of service study ("COSS"), which served as the basis for the Company's proposals for allocating the requested base revenue increase and for setting the residential BCC.

Ms. Hager cites to a March 28, 2019 report by the Public Staff ("Public Staff MSM Report") as the basis in part for her endorsement of the Company's

[1] On March 13, 2020, DEP filed supplemental testimony by Mr. Pirro. I also respond to this supplemental testimony.

COSS.[2] My testimony therefore also addresses the findings and recommendations of this report.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS WITH REGARD TO DEP'S PROPOSAL FOR ALLOCATING THE REQUESTED BASE REVENUE INCREASE.

A: The Commission should reject the Company's proposal for allocating the requested base revenue increase. The Company's proposal relies solely on the results of a cost of service study that does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Specifically, the Company's COSS misallocates distribution costs by: (1) misclassifying a portion of such costs as customer-related by relying on a flawed "minimum-system" analysis to classify distribution costs; and (2) misallocating the demand-related portion of such costs by relying on an allocator that fails to account for the impact of load diversity on distribution equipment sizing and cost. Because of these two errors, the Company's COSS allocates more distribution plant costs to the residential rate classes than is appropriate under generally accepted cost-causation principles.

The Commission should therefore direct DEP to discontinue its use of the minimum-system method for classifying distribution costs in the Company's COSS. Instead, consistent with best practice, DEP should rely on the "basic customer method" for classifying such costs in its COSS. In addition, in order to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes on the basis of each class's diversified peak demand.

---

[2] *Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities*, Docket No. E-100, Sub 162 (March 28, 2019) [hereinafter "Public Staff MSM Report"].

Correcting for the misallocations in the Company's COSS would substantially reduce the allocation of the requested base revenue increase to the residential rate classes. Accordingly, a fair and reasonable approach would be to increase base revenues for the residential rate classes by the same percentage as the overall system-average increase authorized by the Commission, if any.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS WITH REGARD TO DEP'S PROPOSAL REGARDING THE RESIDENTIAL BCC.

A: The Company has not justified its proposal to maintain the residential BCC at its current rate. As explained in more detail below, the Company's proposal runs contrary to long-standing principles for designing cost-based rates since it would allow for the continued inappropriate recovery of usage-driven costs through the fixed residential BCC. The Company's proposal to continue recovering usage-driven costs through the residential BCC would:

- Continue the current subsidization of high-usage residential customers' costs by low-usage customers.
- Dampen price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

Consequently, the Commission should reject the Company's proposal to maintain the monthly BCC for residential customers at its current rate of $14.00 per bill. Instead, I recommend that the residential BCC be reduced to $9.63, reflecting the actual cost to connect a residential customer. Consistent with long-standing cost-causation and rate-design principles, a monthly BCC of $9.63 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Q: PLEASE SUMMARIZE YOUR ASSESSMENT OF THE PUBLIC STAFF MSM REPORT.

A: The Public Staff MSM report fails to make the case for minimum-system classification methods. The Public Staff's endorsement of minimum-system methods rests on its unsubstantiated belief that there is a minimum portion of the cost for the distribution grid which is incurred regardless of demand. This notion of a minimum distribution cost which lies at the foundation of minimum-system methods simply does not comport with standard practice for distribution planning and spending. Utilities do not first incur "minimum" distribution-grid costs for the purposes of connecting customers at zero load and then incur additional costs to meet expected demand. Instead, utilities typically size and invest in distribution systems based on an expectation of customer demands on those systems. In other words, the notion that there is a minimum portion of a distribution grid whose costs are "caused" by (i.e., varies with) the number of customers is an unrealistic hypothetical construct. The reality is that distribution-grid costs in total are primarily driven by customer demand.

This implausibility gap between the imagined and the actual causes of investments in the distribution grid will only grow wider as DEP increases spending on its proposed Grid Improvement Plan. It is therefore long past time for North Carolina's electric utilities to discard this false notion that there is a minimum portion of distribution-grid costs. The Commission should categorically reject as contrary to the public interest the use by DEP and other electric utilities of minimum-system classification methods for either cost-allocation or rate-design purposes. Instead, DEP should be directed to follow best practice by adopting the basic customer method for classifying distribution costs in its cost of service studies. In addition, the Commission should investigate whether discretionary GIP costs, to the extent authorized, should be allocated to rate classes in the Company's COSS commensurate with the benefits to those classes from GIP spending. In this way, the Commission can ensure that distribution costs are allocated in the Company's cost of service studies and recovered through rates in a manner that is consistent with established cost-causation and economic principles.

Q: HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A: In Section II, I describe how the Company's proposal for allocating the requested base revenue increase relies on a cost of service study that over-allocates distribution plant costs to the residential rate classes. In Section III, I propose an alternative approach for allocating any base revenue increase authorized by the Commission in order to correct for the flaws in the Company's COSS. In Section IV, I explain how DEP's proposal for the residential BCC violates long-standing principles of cost-based rate design, would continue unreasonable cross-subsidization within the residential class, and would dampen energy price signals. In Section V, I comment on the Public Staff MS Report. Finally, I reiterate my recommendations in Section VI.

II. <u>DEP'S COSS OVER-ALLOCATES COSTS TO THE RESIDENTIAL RATE CLASSES</u>

Q: PLEASE DESCRIBE THE COMPANY'S REQUESTED REVENUE INCREASE.

A: The Company is requesting that electric retail base rates be increased on average by 18.4% in order to recover an expected revenue deficiency of about $586.0 million in the 2018 test year.[3] Of the total $586.0 million requested base revenue

[3] Derived from data provided in Pirro Supplemental Exhibit 4, attached to *Supplemental Testimony of Michael J. Pirro for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219 (March 13, 2020). The 18.4% value represents the percentage increase over revenues under current rates exclusive of current rider revenues.

increase, DEP proposes to allocate about $340.2 million to residential customers. This amount represents a 21.2% increase over residential test-year base revenues under current rates.[4]

Q: WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL RATE CLASSES?

A: According to DEP witness Michael J. Pirro, the Company's COSS served as the basis for his revenue allocation proposal. Specifically, Mr. Pirro derived the proposed allocation of the base revenue deficiency to rate classes in two steps, each of which relied on the results of the Company's COSS. First, Mr. Pirro allocated the requested base revenue increase to rate classes in proportion to each class's allocation of total rate base in the Company's COSS.[5] Second, Mr. Pirro increased or decreased each class's allocation of the requested base revenue increase by 25% of the increase or decrease, respectively, in each class's revenues under current rates required to achieve the system-average rate of return under current rates.[6]

Q: WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A: The primary purpose of a cost of service study is to allocate a utility's total revenue requirements to rate classes in a manner that reasonably reflects each class's responsibility for such revenue requirements. In other words, the primary purpose of a cost of service study is to attribute costs to rate classes based on how those classes cause such costs to be incurred.

---

[4] *Id.* The $340.2 million amount represents the total allocation to all residential rate schedules. Standard residential service is provided under Rate Schedule RES. Time-of-use residential service is provided under Rate Schedules R-TOUD and R-TOU.

[5] *Direct Testimony of Michael J. Pirro for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219, 11 (March 13, 2020) [hereinafter "Pirro Direct"].

[6] Pirro Supplemental Exhibit 4.

Q: PLEASE DESCRIBE HOW THE COMPANY'S COSS ALLOCATES TOTAL-SYSTEM RETAIL REVENUE REQUIREMENTS TO RATE CLASSES.

A: In order to allocate costs to rate classes, the COSS first separates total costs into production, transmission, distribution, and customer functions. Costs in each function are then classified as energy-, demand-, or customer-related based on whether costs are considered to be "caused" by energy sales, peak demand, or the number of customers, respectively. Finally, costs classified as either energy-, demand-, or customer-related are allocated to rate classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.[7]

Q: DOES THE COMPANY'S COSS REASONABLY ALLOCATE TEST-YEAR REVENUE REQUIREMENTS?

A: No. The Company's COSS does not allocate costs to rate classes in a manner that reasonably reflects each class's responsibility for such costs. In particular, the COSS misallocates distribution costs.

Q: HOW DOES THE COMPANY'S COSS MISALLOCATE DISTRIBUTION COSTS?

A: As described in detail below, the Company's COSS misallocates distribution plant costs by inappropriately classifying a portion of such costs as customer-related. The COSS then compounds this error by allocating demand-related distribution plant costs on the basis of customer maximum demand, rather than based on customer demand coincident with class peaks. Because of these two errors, the Company's COSS allocates more distribution plant costs to the

[7] *Direct Testimony of Janice Hager for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219, 5-6 (October 30, 2019) [hereinafter "Hager Direct"].

residential rate classes than is appropriate under generally accepted cost-causation principles.

A. Misclassification of Distribution Plant Costs

Q: PLEASE DESCRIBE HOW COSTS ARE CLASSIFIED IN THE COMPANY'S COSS.

A: The Company classifies the costs of meters, service drops, and customer services ("customer connection costs") as customer-related in the COSS. In addition, the Company relies on a "minimum-system" analysis to classify a portion of the costs incurred for poles, conductors, conduits, and line transformers ("distribution-grid costs") as customer-related.[8]

The remaining portion of pole, conductor, conduit, and line-transformer costs not classified as customer-related are instead classified as demand-related in the COSS, along with all production and transmission plant and fixed operations and maintenance ("O&M") costs. Finally, fuel and variable O&M costs are classified as energy-related.

Q: PLEASE DESCRIBE HOW THE COMPANY USES THE MINIMUM-SYSTEM ANALYSIS TO CLASSIFY SOME POLE, CONDUCTOR, CONDUIT, AND LINE-TRANSFORMER COSTS AS CUSTOMER-RELATED.

A: The Company's minimum-system analysis attempts to estimate the cost to install the same amount of poles, conductors, conduit, and line transformers as are currently on the distribution system, assuming that each piece of distribution equipment is sized to meet minimal load.[9] In other words, the Company's

[8] Specifically, DEP applies a minimum-system analysis to the costs recorded in FERC accounts 364 (poles, towers, and fixtures), 365 (overhead conductors and devices), 366 (underground conduit), 367 (underground conductors and devices), and 368 (line transformers).

[9] Hager Direct, 14.

minimum-system analysis attempts to estimate the cost to replicate the configuration of the existing distribution grid using "minimum-size" equipment.[10] Consequently, this type of minimum-system analysis is typically referred to as the "minimum-size" classification method.

The Company's COSS classifies the cost of this hypothetical minimum-size distribution grid as customer-related. The remaining test-year cost of the distribution grid is classified as demand-related in the COSS.

Q: DOES THE COMPANY'S MINIMUM-SYSTEM ANALYSIS PRODUCE COST CLASSIFICATIONS THAT ARE CONSISTENT WITH COST-CAUSATION PRINCIPLES?

A: No. The Company's minimum-system analysis suffers from a number of conceptual and structural flaws that result in misclassifications of distribution-grid costs. These misclassifications, in turn, lead to allocations of distribution-grid costs which are contrary to cost-causation principles. Specifically, minimum-system classifications result in an over-allocation of distribution-grid costs to the residential rate classes.

Q: WHY DOES THE COMPANY'S MINIMUM-SYSTEM ANALYSIS PRODUCE COST CLASSIFICATIONS THAT ARE INCONSISTENT WITH COST-CAUSATION PRINCIPLES?

A: The Company's minimum-system analysis is premised on the false notion that DEP incurs a "minimum" amount of distribution-grid costs to serve customers at zero load and then incurs additional costs to meet the total load of those customers. In reality, utilities typically size their distribution systems, and incur

[10] The Company's minimum-system analysis of pole costs does not assume the same number of poles as currently installed on the DEP distribution system. Instead, DEP estimates the number of minimum-size poles required to carry a mile of minimum-size conductor and then calculates the total number of minimum-size poles required based on the number of miles of overhead conductor currently installed on the DEP distribution system.

the costs to build those systems, based on an expectation regarding the total demand of all customers connected to the grid.[11] In other words, distribution-grid costs are typically driven by customer load, not by the number of customers.

Indiana Michigan Power Company offers an example of typical utility practice with respect to the sizing of distribution systems. According to testimony before the Indiana Utility Regulatory Commission, Indiana Michigan Power Company's distribution-grid costs are driven by customer demand, not by the number of customers:

> The minimum system approach of classifying a portion of the costs included in accounts 364-368 as customer related … does not recognize the Company's standard engineering practice of planning and sizing distribution facilities to meet the peak demand of the customers served by those facilities. As such, the peak demand on Company facilities, not the number of customers served by the facilities, causes the Company to incur distribution facility costs.[12]

Contrary to typical engineering and investment practice, the Company's minimum-system analysis posits an imaginary world where some portion of the Company's distribution-grid costs were incurred regardless of customer demand. In this fictional world of the minimum system analysis, spending on the imagined minimum grid is considered to be driven by number of customers and thus classified as customer-related. But in the real world, spending on the actual distribution grid is driven by customer demand and thus appropriately classified as demand-related.[13] Consequently, applying the minimum-size method to the

[11] In fact, it is unlikely that DEP would incur the cost to connect a zero- or minimal-load customer under the Company's line-extension policies and would instead require this customer to bear any such connection cost. The Company's line-extension policies and procedures are set forth in the *Line Extension Plan*, included as part of the electric tariff.

[12] *Pre-Filed Verified Rebuttal Testimony of Michael M. Spaeth*, Indiana Utility Regulatory Commission Cause No. 45235, 11-12 (September 17, 2019).

[13] This part of my testimony addresses cost allocation, not rate design. As I discus below in Section V with regard to the Public Staff's Minimum System Method Report, it would not be

Company's distribution-grid costs yields classifications that are inconsistent with cost-causation.

Q: ARE THERE OTHER ASPECTS OF THE COMPANY'S MINIMUM-SIZE APPROACH TO COST CLASSIFICATION THAT ARE INCONSISTENT WITH COST-CAUSATION PRINCIPLES?

A: Yes. Even if one accepts the false premise of a minimum distribution system, the Company's minimum-system analysis suffers from a number of structural defects which lead to classifications and allocations of distribution-grid costs that are contrary to cost-causation principles.

For one, the Company's approach erroneously assumes that the minimum system would consist of the same amount of equipment (e.g., number of transformers) as the actual system.[14] In reality, load levels help determine the amount of equipment, as well as their size. Minimum-system analyses ignore the effect of loads on the amount or type of equipment installed, classifying some costs as customer-related even though they are really driven by demand. Any such costs misclassified as customer-related will therefore be misallocated to rate classes on the basis of customer number, contrary to cost-causation principles.

For another, the Company's minimum-system analysis fails to account for the fact that even the minimum-size equipment currently installed on the system has some amount of load-carrying capability. Consequently, some portion of the cost for this minimum-size equipment should be classified as demand-related. However, under the minimum-size method, that demand-related portion of the

---

appropriate to recover costs classified as demand-related in the Company's COSS in a residential demand charge.

[14] As noted above, the exception is the Company's assumption with regard to the number of minimum-size poles.

cost of the minimum-sized equipment instead would be misclassified as customer-related.

The failure to account for the load-carrying capability of minimum-size equipment distorts the allocation of distribution-grid costs in two ways. First, the load-carrying portion of minimum-grid costs are misallocated to rate classes on the basis of customer number, contrary to cost-causation principles. Second, the remaining demand-related portion of distribution-grid costs will be allocated to rate classes on the basis of each class's total demand, even though some of that demand was carried by the minimum-size portion of the distribution grid and therefore did not cause those remaining demand-related costs to be incurred. In other words, the Company's COSS will double-allocate the costs to carry a portion of a class's demand: once through the allocation of the load-carrying portion of minimum-grid costs and again through the allocation of the remaining demand-related costs on the basis of the demand carried by the minimum grid.[15]

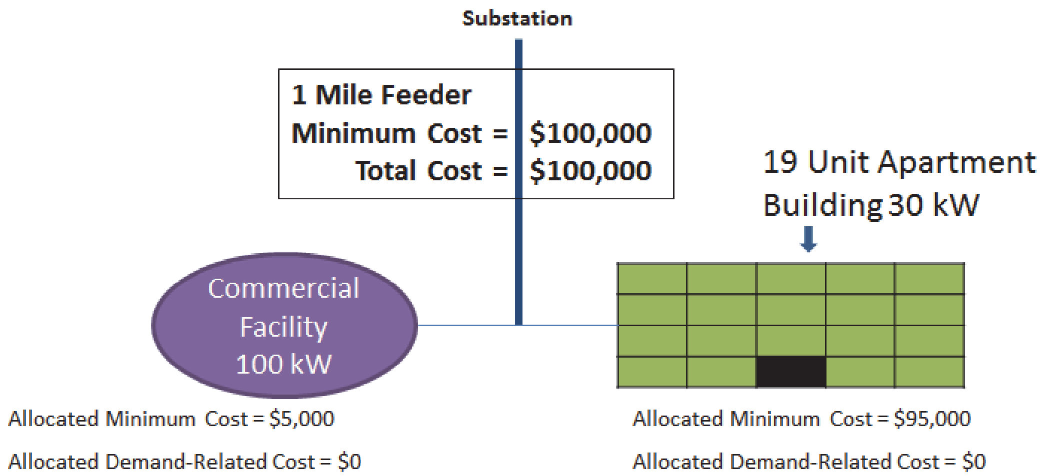
Q: PLEASE PROVIDE AN ILLUSTRATIVE EXAMPLE OF THIS DOUBLE-ALLOCATION PROBLEM.

A: Figures 1a and 1b illustrate this problem of double-allocation of demand-related costs when using the minimum-size method. Figures 1a and 1b assume a hypothetical distribution system consisting of a single one-mile feeder. In the example shown in Figure 1a, there are 20 customers served by the feeder: 19 units in an apartment building with a combined load of 30 kilowatt ("kW") and a single commercial facility with a load of 100 kW. In this example, the minimum-size feeder is assumed to be large enough to cover the combined load on the system, meaning that the minimum cost is equal to the total cost of the feeder.

[15] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs," *Public Utilities Fortnightly*, (July 2, 1981). A copy of this article is attached as Exhibit JFW-2.

Consequently, under the minimum-size approach, 100% of the total cost of the feeder is inappropriately classified as customer-related and the residential class (with 19 of the 20 customer accounts served by the hypothetical distribution system) is allocated 95% of this cost, even though those 19 residential apartment dwellers are responsible for less than 25% of the load.[16]

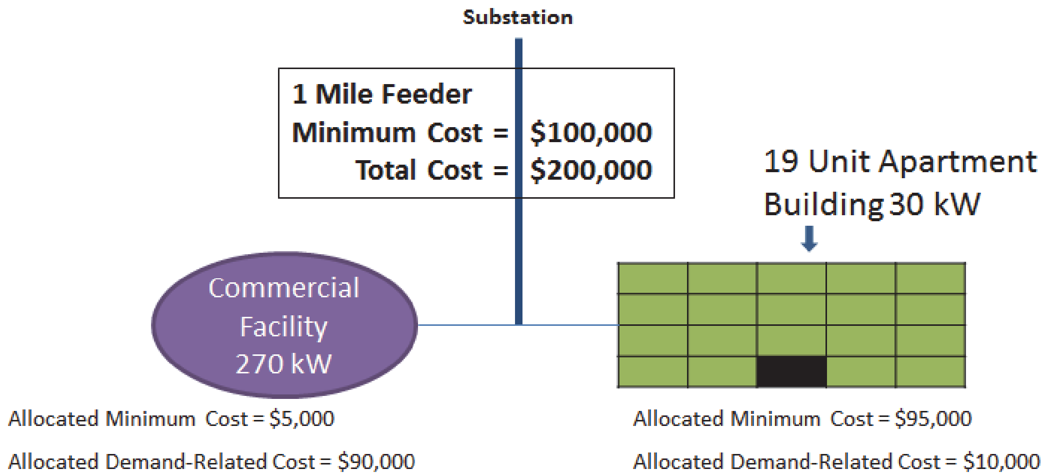
Figure 1a



The example shown in Figure 1b assumes the same number of customers as in Figure 1a. However, in this example, the commercial facility has a load of 270 kW, requiring a larger feeder. As in Figure 1a, the residential class would be allocated 95% of the minimum cost of the feeder. Unlike the case in Figure 1a, however, the residential class would also be allocated 10% of the demand-related feeder costs – those costs in excess of the cost of a minimum-size feeder – even though such costs would not have been incurred without the additional commercial load on the system. Instead, all such excess costs in this example should instead be allocated to the commercial class.

[16] As discussed above, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

Figure 1b



Q: IS THERE AN ALTERNATIVE METHOD USED BY UTILITIES THAT CLASSIFIES DISTRIBUTION COSTS IN ACCORDANCE WITH COST-CAUSATION PRINCIPLES?

A: Yes. Numerous utilities across the country rely on the basic customer method of cost classification to classify distribution costs in accordance with cost-causation principles. Under the basic customer method, only the costs of meters, service drops, and customer services are classified as customer-related and all other distribution costs are classified as demand-related. The Regulatory Assistance Project recently published a comprehensive study of cost-allocation methods which declares the basic customer method to be best practice.[17]

Q: WHICH UNITED STATES UTILITIES RELY ON THE BASIC CUSTOMER METHOD TO CLASSIFY DISTRIBUTION COSTS?

A: I have not done a comprehensive survey of classification methods by U.S. utilities.[18] However, I am aware of a number of utilities which rely on the basic

[17] Jim Lazar, et. al., *Electric Cost Allocation for a New Era: A Manual*, Regulatory Assistance Project, 18 (January, 2020), available at https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/ [Hereinafter "RAP Cost Allocation Manual"].

[18] According to a study commissioned by the National Association of Regulatory Utility Commissioners, the basic customer approach is employed in more than thirty states. *See*

customer method in Arkansas, California, Colorado, District of Columbia, Illinois, Indiana, Iowa, Maryland, Massachusetts, Michigan, Oregon, South Carolina, Texas, Utah, and Washington.

Q: DOES DEP OR ITS UTILITY AFFILIATES IN OTHER JURISDICTIONS USE THE BASIC CUSTOMER METHOD TO CLASSIFY DISTRIBUTION COSTS?

A: Yes. Up until its most recent rate case, DEP in South Carolina had been relying on the basic customer method to classify distribution-grid costs as demand-related.[19] The Company's utility affiliate in Indiana likewise has been using the basic customer method to classify distribution costs for the past 25 years.

Q: HAS DEP ESTIMATED THE IMPACT OF ITS MISCLASSIFICATION OF DISTRIBUTION PLANT COSTS ON THE ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL RATE CLASSES?

A: Yes. In response to a data request, DEP modified its COSS to classify distribution plant costs based on the basic customer method rather than on the minimum-size method.[20] Specifically, DEP classified all pole, conductor, conduit, and line transformer costs as demand-related for this version of the COSS. This modified

---

Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, 30 (December, 2000), available at https://pubs.naruc.org/pub.cfm?id=536F0210-2354-D714-51CF-037E9E00A724.

[19] In a 1988 order granting a rate increase to DEP's predecessor, Carolina Power & Light Company ("CP&L"), the Commission rejected an intervenor's recommendation that CP&L use the minimum-system method to classify distribution costs. *See* Public Service Commission of South Carolina, *Order Granting Increase*, Order No. 88-864, Docket No. 88-11-E, 11 (August 29, 1988). The Public Service Commission explicitly declined to rule on the merits of the Company's proposal to switch from the basic customer method to the minimum-system method in the most recent DEP rate case. *See* Public Service Commission of South Carolina, *Order*, Order No. 2019-341, Docket No. 2018-318-E, p. 64 (May 21, 2019).

[20] DEP second supplemental response to NC Justice Center et al. Data Request Item No. 4-16. Attached as Exhibit JFW-3.

COSS without minimum-system classification of distribution plant costs therefore classifies only the cost of meters, service drops, and customer services as customer-related.

Correcting for the misclassification of distribution plant costs in the Company's COSS substantially reduces the allocation of 2018 test-year base revenue requirements to the residential class. As discussed above, DEP is requesting an increase in base revenues (i.e., excluding rider revenues) of 18.4% on average for all customers and proposing an increase of 21.2% for residential customers. In contrast, under Mr. Pirro's proposed approach for allocating the requested base revenue increase, residential base revenues would be increased by only 19.6% – closer to the system-average increase – if distribution plant costs were correctly classified in the Company's COSS with the basic customer method.

Q: WHAT DO YOU RECOMMEND WITH REGARD TO THE CLASSIFICATION OF DISTRIBUTION PLANT COSTS IN THE COMPANY'S COSS?

A: The classification of distribution plant costs in the Company's COSS does not reasonably reflect cost-causation. The Commission should therefore direct DEP to discontinue its use of the minimum-system method for classifying distribution plant costs in the Company's COSS. Instead, DEP should rely on the basic customer method for classifying such costs in its COSS.

B. Misallocation of Demand-Related Distribution Plant Costs

Q: HOW DOES THE COMPANY'S COSS ALLOCATE DEMAND-RELATED DISTRIBUTION PLANT COSTS?

A: As discussed above, DEP classifies a portion of distribution plant costs as customer-related based on a minimum-system analysis, allocating those costs to rate classes in the COSS based on the number of customers in each class. The remaining portion is then classified as demand-related and allocated to rate classes in the Company's COSS on the basis of what DEP refers to as "non-coincident peak" demand ("NCP"). The Company derives class NCP by summing individual customers' maximum demand during the test year. The NCP allocator derives each class's percentage share of demand-related distribution plant costs as the ratio of: (1) the class NCP for the test year; and (2) the sum of all rate classes' NCPs in the test year.[21]

Q: DOES THE NCP ALLOCATOR REASONABLY REFLECT COST-CAUSATION?

A: No. The NCP allocator does not account for the effect of load diversity on distribution equipment loading and thus does not reasonably reflect the drivers of the Company's distribution plant costs. By failing to account for load diversity, the NCP allocator likely overstates the residential rate classes' contributions to distribution costs and thus over-allocates such costs to the residential classes.

Q: HOW DOES LOAD DIVERSITY AFFECT THE SIZING OF DISTRIBUTION PLANT?

A: Residential customers reach their individual maximum demands on different days and in different hours of the day. This diversity of demand among a group of residential customers served by a piece of shared distribution equipment results in a group peak demand that is lower than the sum of customers' individual maximum demands.

I illustrate the impact of load diversity in Table 1 with an example that assumes that three residential customers take service from a single transformer. For simplicity's sake, this example further assumes that there are four hours in

[21] Hager Direct, 11.

the year and that the three residential customers have hourly demands as shown in Table 1.

Table 1: Impact of Load Diversity

	Customer #1 Demand (kW)	Customer #2 Demand (kW)	Customer #3 Demand (kW)	Total Demand (kW)	
Hour 1	3	2	1	6	
Hour 2	7	4	2	13	
Hour 3	5	6	3	14	Diversified Peak Demand
Hour 4	2	3	4	9	
Maximum	7	6	4	17	Sum of Maximum Demand

As indicated in Table 1, the sum of the individual customers' maximum demands is 17kW in this example. In contrast, the diversified peak demand on the shared transformer is only 14kW, or about 18% less than the sum of individual maximum demands, because of load diversity.

Q: DOES DEP ACCOUNT FOR LOAD DIVERSITY IN THE SIZING OF DISTRIBUTION PLANT?

A: Yes. As is typical for electric utilities, DEP sizes distribution plant to meet the diversified peak demand in total of the group served by that plant, not to meet the sum of the maximum demands of the individual customers in that group. Referring to diversified peak demand as "non-coincident peak" and the sum of maximum demands as "Individual Customer Maximum Demand (ICMD)," Duke Energy states in its response to the Public Staff in Docket No. E-100, Sub 162 that:

> Duke's position is that all customers do not impose their maximum demand on the distribution system at the same time. Rather, individual customers will use their maximum demand at different times than other customers who are served by the same distribution facilities, and as a group, will have a non-coincident peak [i.e., diversified peak] that is less than the group's ICMD. (For obvious reasons, this load diversity is higher the farther away the distribution equipment is from the customer.) <u>Thus, Duke Energy "sizes" distribution equipment to meet this non-coincident peak</u> [i.e., diversified peak].[22]

Q: PLEASE PROVIDE AN EXAMPLE OF HOW DEP ACCOUNTS FOR LOAD DIVERSITY WHEN SIZING DISTRIBUTION EQUIPMENT.

A: In response to discovery in an ongoing rate case in Indiana, Duke Energy Indiana provided a copy of the guidelines used to size transformers in Duke Energy's service territories in the Carolinas and the Midwest.[23] According to these guidelines, DEP sizes transformers based on an estimate of the diversified peak load of the customers sharing the transformer. As indicated in the following excerpt from the guidelines, the Company assumes that load diversity increases with the number of customers taking service from a transformer, i.e. that the ratio of load on the transformer to the sum of the individual customers maximum demand ("coincidence factor") decreases as the number of customers taking service from a transformer increases.

---

[22] "Duke Energy Response to Public Staff Initial Data Request," 11-12 (emphasis added). Provided in Appendix 1 of Public Staff MSM Report.

[23] A copy of this discovery response is attached as Exhibit JFW-4.

Diversity (Coincidence Factor)

Carolinas

Customers	Heat Pump	A/C
1	1	1
2	.695	.82
3	.568	.73
4	.486	.645
5	.427	.58
6	.377	.515
7	.352	.49
8	.337	.475
9	.323	.47
10	.314	.46
11	.314	.46
12 & up	.314	.46

For example, these guidelines indicate that DEP assumes a coincidence factor of 0.486 for the purposes of sizing a transformer that will serve four residential customers with heat pumps. This means that DEP assumes that load on that transformer (i.e., diversified demand) will be less than half of the sum of the maximum demands of the four customers taking service from the transformer (i.e., non-coincident demand), because of the diversity between the individual customer demands.

Q: WHY DOES THE NCP ALLOCATOR OVER-ALLOCATE DEMAND-RELATED DISTRIBUTION PLANT COSTS TO THE RESIDENTIAL CLASS?

A: The NCP allocator over-allocates costs to the residential class because it does not account for the effect of load diversity on equipment sizing and thus on equipment cost.

Specifically, the NCP allocator does not account for the fact that distribution equipment serving many small residential customers can be smaller (and less expensive) than equipment that serves fewer large industrial customers, even when the sum of the residential maximum demands is equal to the sum of industrial maximum demands. As the number of customers served by distribution equipment increases, so too does the diversity of maximum hourly demands among those customers. And as the diversity of maximum demands increases, so too does the variance between the sum of individual customers' maximum hourly demands (i.e., group NCP) and the maximum demand for the group as a whole (i.e., group diversified demand.) By not accounting for load diversity, the NCP allocator allocates cost to classes as if the sizing and cost of distribution equipment is driven by each class's NCP rather than by the class's diversified demand on the equipment.

Q: HAS DEP ESTIMATED THE IMPACT OF ITS MISALLOCATION OF DEMAND-RELATED DISTRIBUTION PLANT COSTS ON THE ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL CLASS?

A: No. In response to a data request, DEP declined to modify its COSS to allocate demand-related distribution plant costs based on diversified peak demand rather than on non-coincident peak, stating that "the Company has not prepared the requested analysis."[24]

While DEP has refused to modify its COSS to correct for the misallocation of demand-related distribution plant costs, it's likely that such a correction would have further reduced the residential allocation of the requested base revenue increase beyond that achieved by correcting for the minimum-system misclassification of distribution plant costs discussed above. In other words, under Mr. Pirro's proposed approach for allocating the requested revenue increase, the residential base revenue increase could be equal to or even less than the 18.4% requested system-average increase if the Company's COSS were

[24] DEP response to NCJC Data Request Item No. 4-5. Attached as Exhibit JFW-5.

corrected for both the minimum-system misclassification of distribution plant costs and the NCP misallocation of the demand-related portion of such costs.

Q: HOW SHOULD DEMAND-RELATED DISTRIBUTION PLANT COSTS BE ALLOCATED?

A: As DEP acknowledges in its response to the Public Staff in Docket No. E-100, Sub 162, the Company sizes its distribution equipment based on diversified peak demand not on customer maximum demand. Thus, in order to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution plant costs should be allocated on the basis of each class's diversified peak demand.[25] Class diversified peak demand is simply the peak hourly demand for the class as a whole.

III. <u>RESIDENTIAL BASE REVENUES SHOULD BE INCREASED BY NO MORE THAN THE APPROVED SYSTEM-AVERAGE INCREASE</u>

Q: PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR INCREASING RESIDENTIAL BASE REVENUES.

A: As discussed above in Section II, the Company is requesting that electric retail base rates be increased on average by 18.4% in order to recover an expected revenue deficiency of about $586.0 million in the 2018 test year. Of the total $586.0 million requested base revenue increase, DEP proposes to allocate about $340.2 million to residential customers. This amount represents a 21.2% increase over residential test-year revenues under current base rates.

Company witness Pirro derived the proposed allocation of the base revenue deficiency to the residential rate classes in two steps, each of which relied on the results of the Company's COSS. Under Mr. Pirro's proposed allocation method,

[25] RAP Cost Allocation Manual, 150.

the residential class is first allocated $329.2 million of the total requested $586.0 million base revenue increase based on the allocation of total rate base in the Company's COSS. The Company's COSS also indicates that residential revenues under current rates would need to be increased by an additional $44.2 million in order to achieve the system-average rate of return under current rates. Under Mr. Pirro's proposed allocation method, the residential class is then allocated an additional $11.0 million, representing 25% of the current under-earnings relative to the system-average achieved rate of return.[26]

Q: WOULD THE COMPANY'S PROPOSAL PROVIDE FOR A FAIR ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL RATE CLASSES?

A: No. As discussed above in Section II, the Company's COSS does not provide a reasonable basis for the allocation of the requested revenue increase to the residential rate classes. Specifically, the Company's COSS over-allocates distribution plant costs to the residential rate classes by: (1) misclassifying a portion of such costs as customer-related; and (2) misallocating the remaining demand-related portion of such costs.

Based on the results of the Company's COSS, Mr. Pirro proposes to increase residential base revenues by 21.2%. In contrast, if the misclassification of distribution plant costs in the Company's COSS were corrected, residential base revenues would increase by only 19.6% under Mr. Pirro's approach for allocating the requested base revenue increase. In fact, with distribution plant costs classified in accordance with cost-causation principles, the Company's COSS shows that the residential rate classes in aggregate are currently over-earning relative to the system-average achieved rate of return. The increase in

[26] Pirro Supplemental Exhibit 4.

residential base revenues would be even less than 19.6% under Mr. Pirro's approach if the misallocation of demand-related distribution plant costs in the Company's COSS were also corrected.

Q: HOW SHOULD ANY BASE REVENUE INCREASE AUTHORIZED BY THE COMMISSION BE ALLOCATED TO THE RESIDENTIAL RATE CLASSES?

A: In light of the magnitude of the misallocation of distribution plant costs in the Company's COSS and the impact of correcting for such misallocations to the residential rate classes, I recommend that base revenues for the residential rate classes be increased on a percentage basis by no more than the overall system-average increase authorized by the Commission, if any.

IV. THE CURRENT BASIC CUSTOMER CHARGE FOR RESIDENTIAL CUSTOMERS IS NOT COST-BASED

Q: WHAT IS THE BASIC CUSTOMER CHARGE?

A: The BCC is a fixed fee charged to each customer on their monthly bill regardless of the customer's energy usage during that month.

Q: WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE BCC FOR RESIDENTIAL CUSTOMERS?

A: The Company proposes to maintain the residential BCC at its current rate of $14.00 per monthly bill.[27]

Q: IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BCC REASONABLE?

A: No. As discussed in detail below, the current rate for the residential BCC inappropriately recovers usage-driven costs through the BCC. This recovery of

[27] Pirro Direct, 12.

usage-driven costs in the fixed BCC rather than through the volumetric energy rate gives rise to cross-subsidization within the residential rate classes and dampens energy price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.[28]

A. DEP's Proposal for the Residential BCC Violates Principles of Cost-Based Rate Design

Q: WHAT ARE THE RELEVANT CONSIDERATIONS IN DESIGNING COST-BASED RATES FOR RESIDENTIAL CUSTOMERS?

A: The primary challenge in rate design is to reflect the costs that customers impose on the system, both to encourage them to use utility resources responsibly and to share costs fairly. Accordingly, fixed customer charges should reflect the fact that each customer contributes equally to certain types of costs (e.g., billing costs) regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs (e.g., distribution-grid costs) at different levels. If usage-driven costs are inappropriately collected through fixed customer charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[29]

---

[28] These problems of cross-subsidization and economically inefficient pricing would be even more pronounced if the residential BCC were increased to the level that Mr. Pirro believes would "better reflect all customer-related costs." [Pirro Direct, 11.] For example, Mr. Pirro believes that it would be appropriate to increase the BCC for residential customers to $31.75 per bill. [Pirro Exhibit 7.] However, such an increase would result in the inappropriate recovery through the BCC of demand-related costs that had been misclassified as customer-related through application of the Company's flawed minimum-system analysis.

[29] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

Q: GIVEN THESE CONSIDERATIONS, WHAT CATEGORIES OF COSTS ARE APPROPRIATELY RECOVERED THROUGH THE VOLUMETRIC ENERGY RATE?

A: In order to provide efficient price signals, volumetric energy rates should be set at levels that recover those categories of costs that tend to increase with customer usage over the long run, including plant, fuel, and O&M costs for the production, transmission, and distribution functions, along with certain customer-service costs that tend to vary with usage such as uncollectible costs.[30] In other words, volumetric energy rates should reflect long-run marginal costs.

As James Bonbright explains in his seminal text, *Principles of Public Utility Rates*:

> In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.[31]

---

[30] Uncollectible costs are the billed amounts not recovered from customers as a result of those customers' non-payment of all or a portion of their monthly bills.

[31] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961), available at: http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[32]

Almost three decades later, Alfred Kahn affirmed Bonbright's opinion in his text, *The Economics of Regulation*:

> … the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC [short-run marginal cost] ….[33]

Q: WHICH COSTS ARE APPROPRIATELY RECOVERED THROUGH FIXED CUSTOMER CHARGES?

A: In contrast to the volumetric energy rate, the fixed customer charge is intended to reflect the cost to connect a customer who uses very little or zero energy to the distribution system. Such "customer connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses. As Bonbright explains:

> But this twofold distinction [between demand and energy in rate design] overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing.[34]

---

[32] *Id.*, 336.

[33] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988).

[34] Bonbright, *op. cit.*, 311.

In their text, *Public Utility Economics*, economists Paul Garfield and Wallace Lovejoy also describe which costs are truly customer-related and therefore appropriately recovered through the fixed customer charge:

> The purpose of both the connection charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer.[35]

More recently, Severin Borenstein restated these principles for designing cost-based fixed customer charges as follows:

> When having one more customer on the system raises the utility's costs regardless of how much the customer uses – for instance, for metering, billing, and maintaining the line from the distribution system to the house – then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. The idea that each household has to cover its customer-specific fixed costs also has obvious appeal on ground of fairness or equity.[36]

Q: IT IS OFTEN CLAIMED THAT FIXED COSTS SHOULD BE RECOVERED THROUGH FIXED CHARGES. HOW DOES THIS CLAIM SQUARE WITH LONG-STANDING PRINCIPLES OF COST-BASED RATE DESIGN?

A: The notion that fixed costs should be recovered through fixed charges sounds appealing, but is often applied inappropriately. The fixed customer charge should

---

[35] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964).

[36] Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.

be designed to recover only those costs that are truly fixed, in other words, those costs that do not vary with customer usage over the long run. Sunk costs that vary with usage over time, but appear to be "fixed" only from a short-run accounting perspective, should not be treated as fixed for purposes of rate design.

Q: IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BCC CONSISTENT WITH THESE LONG-STANDING PRINCIPLES OF COST-BASED RATE DESIGN?

A: No. Contrary to these principles, the Company's proposal would recover through the residential BCC not just customer connection costs – i.e., the costs for meters, service drops, and customer services – but also the costs allocated to the residential class under the Company's COSS for: (1) uncollectible accounts; and (2) customer-related distribution-grid plant.

Q: WHY IS IT INCONSISTENT WITH COST-BASED RATE DESIGN TO RECOVER UNCOLLECTIBLE COSTS THROUGH THE RESIDENTIAL BCC?

A: Uncollectible costs tend to vary with revenues and thus with usage, because the larger the bill amount (due to either increased usage or higher rates), the greater the amount of the bill at risk of being unaffordable and therefore uncollectible. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.[37]

---

[37] This part of my testimony addresses rate design, not cost allocation. I do not dispute the Company's classification of uncollectible costs as customer-related for the purposes of allocating such costs to rate classes. However, no matter how classified for cost-allocation purposes, recovering uncollectible costs through the BCC would be contrary to longstanding principles of cost-based rate design.

Q: HOW DOES DEP ESTIMATE THE CUSTOMER-RELATED DISTRIBUTION-GRID COSTS THAT ARE INAPPROPRIATELY RECOVERED THROUGH THE CURRENT RESIDENTIAL BCC?

A: As discussed in Section II, DEP relies on the results of its minimum-system analysis to estimate the "customer-related" portion of distribution-grid costs.

Q: WHY WOULD IT BE UNREASONABLE FOR DEP TO RECOVER COSTS THROUGH THE RESIDENTIAL BCC THAT WERE CLASSIFIED AS "CUSTOMER-RELATED" USING A MINIMUM-SYSTEM ANALYSIS?

A: As discussed in Section II, any distribution-grid costs that are currently recovered through the residential BCC are actually demand-related costs that have been misclassified as customer-related in the Company's minimum-system analysis. Recovering such demand-related costs through the residential BCC would be contrary to long-standing principles of cost-based rate design.

Even if the results of the Company's minimum-system analysis were accepted for *cost-allocation* purposes, such results should not be used for *rate-design* purposes. Minimum-system analyses overstate the minimum cost *per customer* because they assume that a minimum system carrying minimal load would have the same amount of distribution equipment (e.g., the same number of transformers) as would a distribution system designed to carry actual distribution load. In other words, the minimum-system method assumes that each piece of distribution equipment would serve the same number of customers on average, regardless of whether the customers are average-sized (as for the actual system) or have minimal demand (as for the hypothetical minimum-size system.)

This is not a realistic assumption, since even a minimally sized piece of distribution equipment should be able to serve more minimal-usage customers than the number of average-usage customers served by an average-sized piece of distribution equipment. Consequently, the true distribution-grid cost to serve a customer with minimal usage is likely to be less than that derived using a minimum-system analysis. Indeed, since the minimum-system method attempts to estimate the distribution-grid cost incurred regardless of usage – i.e., the cost to serve load approaching zero – the true minimum distribution-grid cost per customer is zero since distribution equipment that carries zero load can serve an infinite number of customers with zero load.

Q: ONCE THE EXCESS UNCOLLECTIBLE AND CUSTOMER-RELATED DISTRIBUTION COSTS FROM THE MINIMUM-SYSTEM ANALYSIS HAVE BEEN REMOVED, WHAT IS THE RESULTING COST TO CONNECT A RESIDENTIAL CUSTOMER TO THE DISTRIBUTION GRID?

A: As shown in Table 2 below, I estimate that a residential BCC of $9.63 per bill would recover the truly customer-related costs of meters, service drops, and customer services allocated to the residential rate classes. I therefore recommend that the residential BCC be reduced from its current rate of $14.00 to $9.63.

Q: HOW DID YOU DERIVE YOUR ESTIMATE OF THE COST TO CONNECT A RESIDENTIAL CUSTOMER TO THE DISTRIBUTION GRID?

A: In response to a data request, DEP provided the unit cost results from a cost of service study that classifies distribution costs using the basic customer method.[38] These results show an allocation to the residential rate classes of about $147.3 million in customer-related costs. I reduced this amount by my estimate of the customer-related revenues recovered through the $2.85 per bill incremental meter

[38] DEP response to Public Staff Data Request Item No. 60-15. Attached as Exhibit JFW-6.

charge for residential TOU customers.[39] I then further reduced this amount in order to remove uncollectible costs for the reasons discussed above. Dividing the net amount of $138.9 million by the number of residential bills yields a connection cost per residential customer of $9.63 per month.

Table 2: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	$147,293,543	14,423,192	$10.21
Less			
TOU Meter Incremental Revenue	(795,230)	14,423,192	($0.06)
Uncollectible Expense	($7,615,021)	14,423,192	($0.53)
Total	$138,883,292		$9.63

Q: WHAT ACCOUNTS FOR THE $4.37 DIFFERENCE BETWEEN YOUR $9.63 ESTIMATE OF THE RESIDENTIAL CONNECTION COST AND THE CURRENT RATE OF $14.00 FOR THE RESIDENTIAL BCC?

A: The $4.37 difference between my $9.63 estimate of the cost to connect a residential customer and the current $14.00 BCC represents usage-driven costs that would be inappropriately recovered through the fixed customer charge under the Company's proposal.

Q: WHY SHOULD THE COMMISSION BE CONCERNED ABOUT THE RECOVERY OF $4.37 IN USAGE-DRIVEN COSTS THROUGH THE CURRENT RESIDENTIAL BCC?

A: As I discuss below, this recovery of usage-driven costs in the fixed customer charge rather than through the volumetric energy rate gives rise to cross-subsidization within the residential class and dampens energy price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.

---

[39] I estimate TOU meter incremental revenues based on data provided in NCUC Form E-1 Data Request, Item No. 42(c).

B. The Current Residential BCC Creates Intra-Class Cost Subsidies

Q: HOW DOES THE CURRENT RESIDENTIAL BCC CAUSE SUBSIDIZATION WITHIN THE RESIDENTIAL CLASS?

A: As discussed above, the current residential BCC recovers usage-driven costs. Such costs are driven by residential load and are therefore appropriately recovered from each residential customer in proportion to their contribution to class load. To the extent that usage-driven costs are recovered through the fixed customer charge rather than through the volumetric energy rate, residential customers with below-average usage bear a disproportionate share of usage-driven costs and consequently subsidize customers with above-average usage. In other words, a residential customer with below-average usage pays more, and a residential customer with above average-usage pays less, than their fair share of such costs.

Q: WHAT IS THE EXTENT OF THE INTRA-CLASS SUBSIDIZATION UNDER THE CURRENT RESIDENTIAL BCC?

A: The Company estimates about 14.4 million residential bills in the test year.[40] This means that about $63.0 million of usage-driven costs are inappropriately recovered annually through the current residential BCC.[41]

If the usage-driven costs recovered through the current residential BCC were instead recovered through the volumetric energy rate, each residential customer would appropriately contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about

---

[40] The Company's estimate of the number of residential bills in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

[41] The $63.0 million result is derived by taking the product of the annual number of residential bills (14.4 million) and the amount of the current residential BCC in excess of residential connection cost ($4.37 per bill).

16.7 million megawatt-hours.[42] Therefore, if the $63.0 million of usage-driven costs were instead recovered through the volumetric energy rate rather than through the current residential BCC, recovery of those costs would be charged at a rate of 0.38 cents per kilowatt-hour ("¢/kWh").[43] In this case, a residential customer with below-average monthly usage of 600 kWh would contribute about $27 per year toward recovery of the $63.0 million of usage-driven costs while a customer with above-average monthly usage of 1,800 kWh would contribute about $82 per year.[44] Thus, the 1,800 kWh customer would contribute three times more than the 600 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, with the current recovery of $63.0 million of usage-driven costs through the residential BCC, each residential customer contributes about $52 per year toward recovery of such costs, regardless of that customer's usage. A below-average 600 kWh customer therefore pays almost double their fair share of these usage-driven costs with the current BCC while an above-average 1,800 kWh customer pays only 64% of their fair share.

Q: WOULD SUBSIDIZATION OF HIGH-USAGE RESIDENTIAL CUSTOMERS BY LOW-USAGE CUSTOMERS BE ELIMINATED IF THE RESIDENTIAL BCC WERE SET AT YOUR RECOMMENDED RATE OF $9.63?

A: No. Even with the residential BCC set at my estimate of residential connection cost, low-usage customers would likely continue to subsidize high-usage

[42] The Company's estimate of residential sales in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

[43] The 0.38¢/kWh result is derived by dividing $63.0 million by residential sales of 16.7 million megawatt-hours.

[44] Based on data provided in NCUC Form E-1 Data Request, Item No. 42(c), I estimate monthly usage of 1,157 kWh for an average residential customer.

customers' costs because customer charges and energy rates are priced at the cost to serve an average-usage customer. For example, Rate Schedule RES customers who reduce their on-peak (and overall) usage with energy efficiency or rooftop solar generation pay the same energy rate as larger, peakier customers even though the latter customers may impose more generation costs per kWh of usage than the former due to their proportionately greater on-peak usage.

Likewise, lower-usage customers in an apartment building will typically share a service drop, whereas higher-usage single-family homes will typically be connected with their own service drop. Yet, the lower-usage apartment resident will contribute through the BCC the same amount toward recovery of service-drop costs as the higher-usage single-family customer even though the cost of a service drop per customer is lower for the former than for the latter customer.

Finally, all residential customers will contribute the same amount for recovery of Advanced Metering Infrastructure ("AMI") costs through the residential BCC even though these customers will probably not share equally in the benefits from the Company's investment in residential AMI meters. The National Association of Regulatory Utility Commissioners describes cost causation as "an attempt to determine what, or who, is causing costs to be incurred by the utility."[45] In this case, the "what" causing DEP to make discretionary investments in AMI meters is the expectation that such investments would provide benefits to customers, and the "who" are the customers who would share in these benefits as a result of the Company's AMI investments. Thus, in the case of AMI meters, cost-causation requires that customers contribute toward recovery of AMI costs in proportion to their share of the AMI benefits.

[45] National Association of Utility Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, 38 (January 1992).

Within the residential class, higher-usage energy consumers will likely reap greater benefits than lower-usage customers from AMI technologies and services.[46] For example, these higher-usage customers will have more opportunities to take advantage of (and to benefit from) innovative rate designs that reward load shifting than will their lower-usage counterparts. It therefore would be consistent with cost-causation principles for larger users to contribute a greater share toward recovery of AMI costs than smaller users. However, even with the residential BCC set at the cost to connect a residential customer, each residential customer regardless of usage will contribute the same amount toward recovery of AMI costs.

In all of these cases, any differences in the cost to serve smaller and larger customers are socialized across the residential class, resulting in subsidization of high-usage customers by low-usage customers.

C. The Current Residential BCC Dampens Energy Price Signals

Q: DOES THE CURRENT RESIDENTIAL BASIC CUSTOMER CHARGE SEND APPROPRIATE PRICE SIGNALS?

A: No. As discussed above, the current residential BCC is set at a rate that exceeds the cost to connect a residential customer. The amount in excess of customer connection cost represents usage-driven costs that are more appropriately recovered in the volumetric energy rate. The recovery of these usage-driven costs in the current fixed BCC rather than in the volumetric energy rate dampens price signals and discourages economically efficient behavior by residential customers.

---

[46] For a description of the expected direct customer and utility benefits from the Company's investment in AMI meters, see *Direct Testimony of Donald L. Schneider, Jr. for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219 (October 30, 2019).

Q: TO WHAT EXTENT DOES THE CURRENT RESIDENTIAL BCC DAMPEN PRICE SIGNALS PROVIDED BY THE RATE SCHEDULE RES VOLUMETRIC ENERGY RATE?

A: With a fixed amount of revenue requirements to be recovered from Rate Schedule RES customers, the higher the BCC, the lower the volumetric energy rate, and vice versa. With the fixed BCC set at its current rate of $14.00 per bill, DEP proposes a volumetric energy rate of 12.24¢/kWh for Rate Schedule RES customers.[47] If, instead, the BCC were set at the cost-based rate of $9.63, I estimate that the volumetric energy rate would have to be increased to 12.62¢/kWh to recover the same allocated revenue requirement.

In other words, DEP is proposing a Rate Schedule RES energy rate that is 0.38¢/kWh, or about 3%, less than what the volumetric rate would be if the BCC were set at the cost-based rate of $9.63. Thus, the current residential BCC dampens the price signal provided by the volumetric energy rate by about 3%.[48]

Q: HOW WOULD RATE SCHEDULE RES CUSTOMERS LIKELY RESPOND TO THE REDUCTION IN THE ENERGY PRICE SIGNAL RESULTING FROM THE COMPANY'S PROPOSAL TO MAINTAIN THE RESIDENTIAL BCC AT ITS CURRENT RATE?

A: Since the volumetric energy rate under the Company's proposal for the residential BCC would be lower than the volumetric energy rate with a cost-based BCC of $9.63, we would expect Rate Schedule RES customers to consume more energy with the current BCC than they would with a cost-based BCC. The magnitude of

---

[47] DEP proposes a summer rate of 12.63¢/kWh and a non-summer rate of 12.03¢/kWh. The sales-weighted average of these two seasonal rates is 12.24¢/kWh.

[48] If the BCC were instead set at $31.75 per bill, as Mr. Pirro believes would be appropriate, I estimate that the volumetric energy rate would have be set at 10.69¢/kWh in order to recover the Company's proposed allocation of revenue requirements to the RES rate class. At $31.75, the residential BCC would dampen the price signal provided by the volumetric energy rate by about 15%.

the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the current BCC is lower than the volumetric energy rate with a cost-based BCC; and (2) the price elasticity of electricity demand.

Q: WHAT IS THE PRICE ELASTICITY OF ELECTRICITY DEMAND?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies.[49] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[50] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[51]

[49] The citation for this study is provided in Exhibit JFW-7.

[50] For Rate Schedule RES customers, that would be the energy rate.

[51] The citations for these studies are provided in Exhibit JFW-7.

Table 3: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al., on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: WHAT WOULD BE A REASONABLE ESTIMATE OF THE MARGINAL-PRICE ELASTICITY FOR CHANGES IN THE RATE SCHEDULE RES VOLUMETRIC ENERGY RATE?

A: From Table 3, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

Q: WHAT WOULD BE A REASONABLE ESTIMATE OF THE EFFECT ON ENERGY USE FROM THE COMPANY'S PROPOSAL TO MAINTAIN THE CURRENT RATE FOR THE RESIDENTIAL BCC?

A: As discussed above, if the residential BCC continued at $14.00, the Rate Schedule RES volumetric energy rate would be about 3% less than it would be if the BCC were set at $9.63. Assuming an elasticity of –0.3, this 3% reduction in the volumetric energy rate would result in an increase in energy consumption of about 0.9% for the average Rate Schedule RES customer. This means that all else equal, Rate Schedule RES load after a few years with a $14.00 BCC is expected to be about 0.9% higher than it would be if the BCC were set at the cost-based rate of $9.63.

For comparison, DEP forecasts that residential energy-efficiency savings in both North and South Carolina will increase each year over the next five years by an amount equivalent to about 0.3% of forecasted annual residential energy sales.[52] Assuming that such savings are spread uniformly across all residential rate classes in the Company's North and South Carolina service territories, the consumption increase from customers on Rate Schedule RES due to the Company's proposal to retain the current $14.00 BCC would undo about three years of energy-efficiency savings.

V. <u>THE PUBLIC STAFF MSM REPORT FAILS TO MAKE THE CASE FOR MINIMUM-SYSTEM CLASSIFICATION METHODS</u>

Q: WHY DID THE PUBLIC STAFF ISSUE ITS REPORT ON THE MINIMUM SYSTEM METHODOLOGY?

A: In its order in the previous rate case for Duke Energy Carolinas, the Commission directed the Public Staff to determine whether continued use of minimum-system approaches is warranted for cost-allocation purposes:

> Just considering the grid modernization programs alone suggests that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. The implications of using a suboptimal methodology or incorrectly applying an otherwise acceptable methodology, could be significant in the future. The Commission concludes that a more focused and explicit evaluation of options for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities is warranted. Therefore, the Commission directs the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate.[53]

---

[52] Estimated based on data regarding residential sales and energy efficiency savings for the entire DEP service territory provided in response to NC Justice Center et al. Data Request Item No. 4-1. Attached as Exhibit JFW-8.

[53] North Carolina Utilities Commission, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Subs 819, 1110, 1146, and 1152, 87 (June 22, 2018).

Q: DOES THE PUBLIC STAFF MSM REPORT COMPLY WITH THE COMMISSION'S DIRECTIVE TO "DOCUMENT A BASIS FOR CONTNUED USE OF MINIMUM SYSTEM" FOR COST-ALLOCATION PURPOSES?

A: No. In fact, the Public Staff MSM Report offers no specific guidance or recommendations regarding the appropriate approach for classifying distribution costs in a cost of service study. Nor does the report address whether the specific minimum-system methods used by each of the electric utilities are reasonable. Instead, the Public Staff simply states in the report that it "believes" generally that it is reasonable to use the results of a minimum-system approach "for establishing the maximum amount to be recovered in the fixed or basic customer charge" and to use the results a basic customer approach to determine the "minimum amount recovered in the fixed charge."[54]

This general belief notwithstanding, the Public Staff recommends that the Commission "request that NARUC, or some other independent entity, undertake a study of these issues from a national perspective, so as to gain insight from best practices and ideas across the country."[55]

Q: HOW DO YOU RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION FOR A NATIONAL STUDY OF DISTRIBUTION COST CLASSIFICATION BEST PRACTICES?

A: The Regulatory Assistance Project ("RAP") commissioned such a national study and published the results of that study in January of this year. <u>The RAP study concludes that the basic customer method represents best practice with respect to the classification of distribution costs.</u>[56]

---

[54] Public Staff MSM Report, 16-17.

[55] *Id.*, 17.

[56] RAP Cost Allocation Manual, 18.

Q: WHAT IS THE BASIS FOR THE PUBLIC STAFF'S BELIEF THAT THE RESULTS OF A MINIMUM-SYSTEM ANALYSIS SHOULD BE USED TO SET THE MAXIMUM AMOUNT TO BE RECOVERED THROUGH THE CUSTOMER CHARGE?

A: The Public Staff's endorsement of minimum-system methods as the basis for designing the customer charge rests on its unsubstantiated belief that there is a minimum portion of the cost for the distribution grid which is incurred regardless of demand.[57] By the Public Staff's logic, these minimum costs are "fixed" – i.e., they do not vary with customer demand – since they are incurred regardless of customer demand. Consequently, Public Staff asserts that recovery of such costs in the volumetric energy rate would give rise to intra-class cross-subsidization.[58]

Q: IS THIS IDEA OF A MINIMUM PORTION OF UTILITY SPENDING ON DISTRIBUTION SYSTEMS A REALISTIC PORTRAYAL OF TYPICAL DISTRIBUTION PLANNING PRACTICE?

A: No. As discussed above in Section II, this notion of a minimum distribution cost which lies at the foundation of minimum-system methods simply does not comport with standard practice for distribution planning and spending. Utilities do not first incur "minimum" distribution-grid costs for the purposes of connecting customers at zero load and then incur additional costs to meet expected demand. Instead, as described in the textbook *Electric Power Distribution System Engineering*, utilities typically size and invest in distribution systems based on an expectation of customer demands on those systems:

---

[57] Public Staff MSM Report, 8.

[58] *Id.*, 9.

> The objective of distribution system planning is to assure that the growing demand for electricity, in terms of increasing growth rates and high load densities, can be satisfied in an optimum way by additional distribution systems … which are both technically adequate and reasonably economical.[59]

> Therefore, distribution system planning starts at the customer level. The demand, type, load factor, and other customer load characteristics dictate the type of distribution system required.[60]

> The load growth of the geographical area served by a utility company is the most important factor influencing the expansion of the distribution system.[61]

In other words, the notion that there is a minimum portion of a distribution grid whose costs are incurred regardless of customer demand is unrealistic. The reality is that distribution-grid costs in total are primarily driven by customer demand.

Q: IS THIS NOTION OF A MINIMUM PORTION OF DISTRIBUTION INVESTMENTMENT ANY MORE PLAUSIBLE WHEN APPLIED TO THE COMPANY'S PROPOSED INVESTMENTS IN THE GRID IMPROVEMENT PLAN ("GIP")?

A: No. To the contrary, it makes no sense to apply the minimum-system construct to GIP costs since these investments are in no way intended to simply connect customers to the distribution grid. Instead, as described by Company witness Jay W. Oliver, DEP has purportedly designed the Grid Improvement Plan to more reliably, intelligently, and economically serve load in the 21st century.[62]

---

[59] Turan Gonen, *Electric Power Distribution System Engineering*, McGraw-Hill, Inc., 3-4 (1986).

[60] *Id.*, 4.

[61] *Id.*, 5.

[62] *Direct Testimony of Jay W. Oliver for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219, 9 (October 23, 2019).

Q: SHOULD ALL GIP COSTS INSTEAD BE ALLOCATED ON THE BASIS OF CLASS PEAK DEMAND?

A: Not necessarily. According to Mr. Oliver, the primary driver of the Company's discretionary investments in the Grid Improvement Plan is the expected economic benefits from such investments.[63] Thus, from a cost-causation perspective, these discretionary investments are "caused" by, and therefore appropriately allocated in proportion to, the expected benefits from such investments.

The Maryland Public Service Commission came to just such a conclusion with respect to Baltimore Gas and Electric's proposed allocation of its discretionary "Smart Grid Initiative" costs:

> [Maryland Office of People's Counsel] notes, and we agree, that <u>contrary to cost-causation principles</u>, the [embedded cost of service study] does not allocate Smart Grid Initiative costs to customer classes commensurate with the allocation of Smart Grid benefits to those classes.[64]

On that basis, the Maryland commission committed to considering a benefits-based approach for allocating smart grid investments in future rate cases.[65] I urge the Commission to likewise consider the merits of a benefits-based approach to allocating the Company's discretionary GIP costs to the extent those costs are authorized.

---

[63] *Id.*, 12.

[64] Maryland Public Service Commission, Order No. 87591, Case No. 9406, 187 (June 3, 2016) [emphasis added].

[65] *Id.*, 184.

Q: DOES THE PUBLIC STAFF LOOK TO THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS' ("NARUC") *ELECTRIC UTILITY COST ALLOCATION MANUAL* FOR SUPPORT OF ITS ENDORSEMENT OF MINIMUM-SYSTEM METHODS?

A: Yes. Noting that NARUC's Electric Utility Cost Allocation Manual ("NARUC Manual") "continues to be considered an important resource for the calculation and allocation of electric utility cost of service," the Public Staff MSM Report highlights the fact that the NARUC Manual describes only minimum-system methods and not the basic customer method as possible approaches for classifying distribution-grid costs.

Q: IS IT TRUE THAT THE NARUC MANUAL DOES NOT INCLUDE THE BASIC CUSTOMER METHOD AS A POSSIBLE APPROACH FOR CLASSIFYING DISTRIBUTION PLANT COSTS?

A: No. The Public Staff is incorrect in its claim that the basic customer classification method is not included in the NARUC manual. To the contrary, the NARUC Manual describes the basic customer method as a classification option in the discussion of marginal cost of service studies:

> A number of analysts have argued, and commissions have accepted, that the customer component of the distribution system should only include those features of the secondary distribution system located on the customer's own property. Portions of the distribution system that serve more than one customer cannot be avoided should one customer cancel service. Similarly, if the customer component of the marginal distribution cost is described as the cost of adding a customer, but no energy flows to the system, there is no reason to add to the distribution lines that serve customers collectively or to increase the optimal investment in the lines that are carrying the combined load of all customers. Therefore, the marginal customer cost of the jointly used distribution system is zero.[66]

[66] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 136 (January, 1992).

Moreover, according to a 1992 letter from the Washington Utilities and Transportation Commission ("WUTC") to the chair of the NARUC task force responsible for drafting the NARUC Manual, earlier drafts of the manual included a discussion of the basic customer method in the chapter on embedded cost of service studies.[67] This discussion was inexplicably removed from the chapter on embedded cost of service studies before final publication.

Q: DOES THE FACT THAT THE BASIC CUSTOMER METHOD WAS NOT DISCUSSED IN THE CHAPTER ON EMBDEDDED COST OF SERVICE STUDIES INDICATE THAT THIS METHOD WAS NOT WIDELY USED AT THAT TIME?

A: No. Despite the short shrift given to the basic customer method in the NARUC Manual, the fact is that the use of this classification method was long-established and widespread at that time. According to the 1992 letter from the WUTC:

> Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" [i.e., minimum-size] 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.[68]

Indeed, as discussed above in Section II, the Company or its predecessor was using the basic customer method in South Carolina before the NARUC Manual was published and continued to rely on this classification method for more than two decades thereafter. And despite the fact that the chapter on embedded cost of service studies does not discuss the basic customer method, the

---

[67] I attach a copy of this letter as Exhibit JFW-9.

[68] Exhibit JFW-9. Emphasis in original.

Company's affiliate in Indiana chose to adopt this classification method two years after publication of the NARUC Manual.

Q: DO YOU HAVE ANY OTHER COMMENTS REGARDING THE PUBLIC STAFF MSM REPORT?

A: Yes. The Public Staff contends in its report that costs classified as demand-related in a cost of service study should be recovered through demand charges.[69] The Public Staff furthermore recommends that electric utilities "utilize data gained from AMI meters to implement … demand charges for all rate classes."[70]

The Commission should reject any such recommendation for the residential rate classes. Residential rates designed to formulaically reflect cost classifications in a cost of service study would neither reflect cost causation nor provide appropriate price signals. In particular, recovery of demand-related costs through a residential demand charge would dampen price signals for conservation, promote inefficient customer behavior, and undermine customers' ability to control electricity costs.

Q: WHY WOULD A RESIDENTIAL DEMAND CHARGE DAMPEN PRICE SIGNALS FOR CONSERVATION, PROMOTE INEFFICIENT CUSTOMER BEHAVIOR, AND UNDERMINE CUSTOMERS' ABILITY TO CONTROL ELECTRICITY COSTS?

A: Demand charges on a monthly bill are typically determined based on the customer's maximum demand, whenever that maximum occurs during the month. In order to control monthly demand costs, customers would therefore need to have detailed information regarding their load profiles for each day of the month as well as an in-depth understanding of which combination of appliance- or

[69] Public Staff MSM Report, 8.

[70] *Id.*, 17.

equipment-usage gives rise to monthly maximum demands. Even with such information and knowledge, it would be difficult for a residential customer to reduce demand charges, since even a single failure to control load during the month would result in the same demand charge as if the customer had not attempted to control load at all.

A demand charge would also provide little or no incentive for residential customers to take actions that reduce distribution-system costs. As discussed above in Section II, distribution equipment costs typically are driven by the diversified peak load for all customers sharing the equipment. An individual customer is unlikely to reach her maximum demand at the same time as when the diversified peak on the distribution system occurs. Thus, a demand charge would provide an incentive to a residential customer to control load at the time that customer reaches her individual maximum demand, which does not necessarily correspond to the time of peak load on the distribution system. In fact, some customers might respond to a demand charge by shifting loads from their own peak to the peak hour on the local distribution system, thereby increasing their contribution to maximum or critical loads on the local distribution system and further stressing the system during peak periods.

Finally, shifting recovery of demand-related costs from the energy rate to a demand charge would send the wrong energy price signal. Shifting demand-related costs to a demand charge would lower the energy rate and thereby perversely encourage increased energy consumption, some of which might occur at times of peak load on the distribution system – when energy conservation is most needed. Shifting costs from the energy rate to a demand charge could therefore increase distribution system costs and offset any (limited) benefits from a residential demand charge.

Severin Borenstein aptly summed up the shortcomings (and the antiquated nature) of demand charges when he wrote: "It is unclear why demand charges still exist."[71]

Q: WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THE PUBLIC STAFF MSM REPORT?

A: The Commission should give no weight to the Public Staff's endorsement of minimum-system classification methods since that endorsement rests on the Public Staff's unsubstantiated belief that there is a minimum portion of the cost for the distribution grid which is incurred regardless of demand. This notion of a minimum distribution cost is an unrealistic hypothetical construct which does not comport with standard practice for distribution planning and spending.

The reality is that distribution-grid costs are primarily driven by customer demand. And it is the basic customer classification method, not minimum-system methods, which classifies distribution-grid costs consistent with this reality. In other words, the basic customer method represents best practice for classifying distribution costs.

It is long past time for North Carolina's electric utilities to discard this false notion that there is a minimum portion of distribution-grid costs. It is also past time to stop treating a 1992 NARUC Manual as the final, cast-in-stone word on distribution cost classification, and to finally acknowledge that the NARUC Manual does not accurately portray best practice at the time of its publication or represent best practice for classifying distribution spending by electric utilities today.

---

[71] Severin Borenstein, "The Economics of Fixed Cost Recovery by Utilities," in *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Lawrence Berkeley National Laboratory, 60 (2016). Available at http://eta-publications.lbl.gov/sites/default/files/lbnl-1005742.pdf.

VI. <u>RECOMMENDATIONS</u>

Q: WHAT DO YOU RECOMMEND TO THE COMMISSION?

A: I recommend that the Commission:

- Reject the Company's use of a minimum-system analysis to classify distribution plant costs in its COSS and instead direct DEP to classify such costs using the basic customer classification method.
- Reject the Company's use of the NCP allocator to allocate demand-related distribution plant costs in its COSS and instead direct DEP to allocate such costs based on class diversified peak demand.
- Increase base revenues for the residential rate classes by no more than the overall system-average percentage increase authorized by the Commission, if any.
- Deny the Company's request to maintain the residential BCC at its current rate of $14.00 per bill and instead direct DEP to reduce the rate to $9.63 per bill.
- Investigate whether discretionary GIP costs, to the extent authorized, should be allocated to rate classes in the Company's COSS commensurate with the benefits to those classes from GIP spending.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Jonathan F. Wallach on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 13th day of April, 2020.

s/ David L. Neal

David L. Neal