BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

In the Matter of:	)	
	)	
Application of Duke Energy Progress, LLC	)	**Docket No. 2018-318-E**
for Adjustments in Electric Rate Schedules	)	
and Tariffs	)	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

SOUTH CAROLINA STATE CONFERENCE OF THE NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, AND UPSTATE FOREVER

Resource Insight, Inc.

MARCH 4, 2019

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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 U.S. and Canada. 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 South Carolina State Conference of the National Association for the Advancement of Colored People ("SC NAACP"), the South Carolina Coastal Conservation League ("CCL"), and Upstate Forever.

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring the following exhibits:

- Exhibit JFW-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- Exhibit JFW-2: Citations to Marginal-Price Elasticity Studies

Q: What is the purpose of your testimony?

A: On November 8, 2018, Duke Energy Progress, LLC ("DEP" or "the Company") filed with the Public Service Commission of South Carolina ("Commission") an application and supporting testimony for approval of increased electric rates and charges. My testimony explains why the Commission should reject the Company's proposal to increase the monthly Basic Facilities Charge ("BFC") for residential customers.[1] I respond to the testimony of Company witness Janice Hager regarding the Company's cost of service study ("COSS"), which served as the basis for its proposal to increase the BFC, and the testimony of Company witness Steven B. Wheeler regarding DEP's proposed increase in the BFC.

Q: Please summarize your findings and recommendations.

A: The Company has not justified its proposal to more than triple the residential BFC. The Company proposes to increase the residential BFC in

[1] The Company also proposes to include in the BFC for Schedule R-TOUD customers an additional monthly fixed charge to cover the cost of time-of-use meters. I do not address this proposal.

order to recover all costs classified as "customer-related" in its cost of service study ("COSS"). However, contrary to long-standing Commission precedent, DEP has classified a portion of the cost of its distribution grid as customer-related in the COSS based on a "minimum-system" analysis.[2] This inherently flawed analysis erroneously classifies some distribution-grid costs—a portion of the cost of poles, wires, conduits, and transformers—as customer-related, even though they are in fact driven by usage and therefore properly classified as "demand-related." The Company's COSS thereby overstates the amount of customer-related costs appropriately recovered through the residential BFC.

Accordingly, the Commission should reject the Company's reliance on a minimum-system analysis to classify distribution-grid costs as customer-related in the COSS. Instead, consistent with this Commission's long-standing precedent, DEP should classify all such distribution-grid costs as demand-related. Only the costs incurred by DEP to connect customers to the distribution grid – i.e., the cost of meters, service drops (the line connecting a residence to the grid) and meter-reading, billing, and other customer-service expenses – should be classified as customer-related.

The Company's proposal to recover distribution-grid costs through the residential BFC also runs contrary to established principles for designing cost-based rates since it would inappropriately shift recovery of costs driven by usage from the volumetric energy rate to the fixed BFC. As explained in

[2] 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. Order No. 88-864, Docket No. 88-11-E, 11 (August 29, 1988).

more detail below, the Company's proposal to recover usage-driven costs through the residential BFC would:

- Lead to subsidization of high-usage residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Company's low-usage residential customers.
- Dampen price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.

Consequently, the Commission should reject the Company's proposal to increase the BFC for residential customers. Instead, consistent with enduring cost-causation and rate-design principles, I recommend that the monthly BFC be set at $9.23 per residential customer to reflect the cost to connect a residential customer.[3]

Q: How is the rest of your testimony organized?

A: In Section II, I describe the Company's proposal for increasing the residential BFC. In Section III, I discuss how the Company's COSS misclassifies demand-related distribution-grid costs as customer-related. In Section IV, I explain how DEP's proposal to increase the residential BFC violates long-standing principles of cost-based rate design. In Section V, I discuss how DEP's proposal would give rise to unreasonable cost subsidization within the residential class. In Section VI, I discuss how the

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[3] In Docket No. 2018-319-E, I recommended that the BFC for Duke Energy Carolinas' residential rate classes be increased from current levels by the same percentage as the revenue increase ultimately authorized by the Commission in that proceeding for those classes. I do not adopt that recommendation for this proceeding because it would likely result in a residential BFC that exceeds the cost to connect a Duke Energy Progress residential customer and therefore would unduly harm low-usage customers.

Company's proposal would dampen energy price signals. Finally, I provide my conclusions and recommendations in Section VII.

II. DEP's Proposal to Increase the Residential BFC

Q: What is the Basic Facilities Charge?

A: The BFC 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 BFC for residential customers?

A: For residential customers taking standard service under Schedule RES, DEP proposes to more than triple the BFC from $9.06 to $29.00 per customer per month. For residential customers taking time-of-use service under Schedule R-TOUD, DEP proposes to nearly triple the BFC from $11.91 to $31.85 per customer per month.[4]

Q: What is the basis for the Company's proposal to increase the residential BFC?

A: According to Company witness Wheeler, DEP proposes to increase the residential BFC in order to recover the residential classes' share of the costs classified as customer-related in the Company's COSS.[5]

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[4] Wheeler Direct Exhibit Nos. 2 and 5, attached to *Direct Testimony of Steven B. Wheeler for Duke Energy Progress, LLC*, Docket No. 2018-318-E (November 8, 2018) [hereinafter "Wheeler Direct"]. The current BFC for Schedule R-TOUD customers is set at the current Schedule RES BFC ($9.06) plus $2.85 for the cost of a time-of-use meter. The Company proposes to set the BFC for Schedule R-TOUD customers at the proposed Schedule RES BFC ($29.00) plus $2.85.

[5] Wheeler Direct, 14.

Q: Does the Company's COSS provide a reasonable basis for increasing the residential BFC?

A: No. As discussed below in Section III, the Company's COSS erroneously classifies some distribution costs as customer-related and therefore overstates the amount of customer-related costs that are appropriately recovered through the residential BFC.

Q: What is the purpose of the Company's COSS?

A: The purpose of the COSS is to allocate the Company's total revenue requirement to the various rate classes in a manner that reasonably reflects each class's contribution to that revenue requirement.

Q: Please describe how the total revenue requirement is allocated to rate classes in the Company's COSS.

A: In order to allocate the total revenue requirement to rate classes, the COSS first separates that total into production, transmission, distribution, and customer cost 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 customer classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.

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 as customer-related in the COSS. As I discuss below in Section III, these are the only categories of costs that are properly classified as customer-related.

In addition, the Company relies on a "minimum-system" analysis to classify some distribution-grid costs – a portion of pole, conductor, conduit, and line-transformer costs – as customer-related. As discussed in Section III, the minimum-system classification methodology is fundamentally flawed and incorrectly classifies distribution-grid costs as customer-related.

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.[6] In other words, the Company's minimum-system analysis attempts to estimate the cost to replicate the configuration of the existing distribution grid using "minimum-size" equipment.

The Company's COSS classifies the cost of this hypothetical minimum-size distribution grid as customer-related. The difference between the total cost of the distribution grid and the estimated cost of the

[6] *Direct Testimony of Janice Hager for Duke Energy Progress, LLC*, Docket No. 2018-318-E, 12 (November 8, 2018) [Hereinafter "Hager Direct"].

hypothetical minimum-size distribution grid is classified as demand-related in the Company's COSS.

Q: Is there another method that utilities typically use to classify distribution costs?

A: Yes. 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.

Q: Does DEP propose to recover all of the costs classified as customer-related in its COSS through the residential BFC?

A: Yes. Based on the minimum-system approach, the Company's COSS estimates a customer-related cost of $28.90 per residential bill.[7] The Company proposes to collect this amount in full through the BFC for standard-service and time-of-use residential customers.

III. DEP's COSS Misclassifies Distribution Costs

Q: Is the Company's proposal to classify distribution costs based on a minimum-system analysis a break from past practice?

A: Yes. In its previous general rate case in 2016, DEP relied on a modified version of the Basic Customer method which classified meter, service-drop, and a portion of line-transformer costs as customer-related, and all other distribution costs as demand-related.[8]

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[7] Calculated based on data regarding customer-related costs and the number of residential bills provided in the Company's responses to Vote Solar Data Request Nos. 1-20 and 1-25, respectively.

[8] Hager Direct, 12.

The 2016 proceeding was the Company's first general rate case since 1988. As in the 2016 proceeding, Carolina Power & Light Company (DEP's predecessor) did not rely on the minimum-system method to classify distribution costs in the 1988 general rate case. In fact, the Commission in the 1988 proceeding explicitly rejected a request by an intervening party for CP&L to use the minimum-system method.

Q: Has DEP explained why it decided in this proceeding to switch from its modified Basic Customer classification method to the minimum-system classification method?

A: No. Instead, Company witness Hager simply describes the various minimum-system classification approaches and then opines that the Basic Customer method would yield cost classifications that are "counter to cost causation principles."[9]

Q: Do you agree with Ms. Hager's contention that the Basic Customer method produces cost classifications that are inconsistent with cost-causation principles?

A: No. To the contrary, it is the minimum-system classification approach adopted by DEP in this proceeding which classifies distribution costs inconsistently with cost-causation principles.

Q: Why are minimum-system classifications inconsistent with cost-causation?

A: The minimum-system method suffers from a number of fundamental flaws which lead to classifications that are contrary to cost-causation principles.

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[9] Hager Direct, 15.

For one, the minimum-system approach implausibly assumes that a utility would incur costs to build a distribution grid to serve customers that have no load. As noted in a study by the Regulatory Assistance Project:

> … the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal — these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered — but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all.[10]

For another, the minimum-system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units, as well as their size. Minimum-system analyses ignore the effect of loads on the number of units installed, or the type of equipment installed, classifying some costs as customer-related even though they are really driven by demand.

Finally, the minimum-system method 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-system method, that demand-related

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[10] Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, 31 (December, 2000), available at https://www.raponline.org/wp-content/uploads/2016/05/rap-weston-chargingfordistributionutilityservices-2000-12.pdf.

portion of the cost of the minimum-sized equipment is instead misclassified as customer-related.[11]

Q: What is the magnitude of misclassified cost under the Company's minimum-system classification?

A: I estimate that about $31.4 million of the distribution-grid costs allocated to the residential rate classes in the COSS have been misclassified as customer-related under the Company's minimum-system method.

Q: How did you derive your estimate of misclassified cost?

A: In response to a data request, DEP provided the unit cost results from its COSS and from a revised cost of service study that classifies distribution costs using the Basic Customer method.[12] These results show that the Company's COSS classifies about $47.6 million of residential revenue requirements as customer-related, while the revised cost of service study based on the Basic Customer method classifies about $16.2 million of residential revenue requirements as customer-related. The $31.4 million difference between these two results represents demand-related distribution-grid costs that have been misclassified as customer-related under the Company's minimum-system classification method.

Q: How would these misclassified costs be recovered under the Company's proposal for the residential BFC?

A: As noted in Section II, DEP proposes to recover through the residential BFC all costs that the Company's COSS classified as customer-related (and

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[11] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, (July 2, 1981).

[12] DEP response to Vote Solar Data Request No. 1-20.

allocated to the residential classes). Thus, the proposed residential BFC would recover not just costs that are truly customer-related but also those distribution-grid costs that are erroneously classified as customer-related in the Company's COSS.

Q: What do you recommend with regard to the Company's proposal to rely on the minimum-system method to classify distribution costs in its cost of service study?

A: The Commission should reject the Company's proposal to break with its long-standing practice and begin using the minimum-system method to classify distribution-grid costs in its cost of service studies. Instead, DEP should be directed to continue classifying distribution costs using the Basic Customer method, but without classifying a portion of line-transformer costs as customer-related as it did in its 2016 cost of service study.

IV. DEP's Proposed Increase to the Residential BFC Violates Principles of Cost-Based Rate Design

Q: How did DEP use the results of its COSS in the design of proposed rates for the residential rate classes?

A: As discussed above in Section II, the Company proposes to set the residential BFC at the amount that would recover the residential classes' share of costs classified as customer-related with the minimum-system method in the COSS. The Company further proposes to set the energy rate for each residential rate class at the amount that would recover the difference between each class's share of requested total revenues and the revenues collected from that class through the proposed BFC.

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 share costs fairly and to encourage economically efficient usage of utility resources. Accordingly, fixed customer charges should reflect the fact that each customer contributes equally to certain types of 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 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.[13]

Q: Given these considerations, what categories of costs are appropriately recovered through the volumetric energy rate?

A: In order to provide cost-based price signals, volumetric energy rates should be set at levels that recover those categories of costs that are driven by customer usage over the long run. This includes 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.[14]

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[13] 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.

[14] 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.

In other words, volumetric energy rates should reflect long-run marginal costs. As James Bonbright concluded in his seminal text *Principles of Public Utility Rates*:

> … 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.[15]

Almost three decades later, Alfred Kahn affirmed Bonbright's opinion in his *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 [short-run marginal cost] ….[16]

Q: Which costs are appropriately recovered through the fixed customer charge?

A: In contrast to the volumetric energy rate, the fixed customer charge should reflect the cost to connect a customer who uses very little (or even zero) energy to the distribution grid. Such "customer connection costs" are limited to the costs of a meter and service drop (including plant and maintenance) and meter-reading, billing, and other customer-service expenses.

[15] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 348-336 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/ principles_of_public_utility_rates.pdf.

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

Q: What is the basis for your opinion regarding which costs are appropriately recovered through the fixed customer charge?

A: My opinion is based on established and enduring rate-design principles. For example, Bonbright explains 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.[17]

In their *Public Utility Economics*, 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 … the service 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.[18]

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

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

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

> 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.[19]

Q: Is the Company's proposal for the residential BFC consistent with these long-standing principles of cost-based rate design?

A: No. Contrary to these principles, DEP proposes to recover through the residential BFC not just customer connection costs – i.e., the costs for meters, service drops, and customer services – but also the costs allocated to the residential classes under the COSS for: (1) "customer-related" distribution-grid plant; (2) Advanced Metering Infrastructure ("AMI meters"); and (3) uncollectible costs.

Q: How does DEP estimate the customer-related distribution-grid cost per residential customer proposed for recovery through the residential BFC?

A: As discussed in Section II, DEP relies on the results of its minimum-system analysis to estimate the "customer-related" distribution-grid cost per residential customer. Specifically, as discussed in Section III, the Company's COSS allocates to the residential rate classes in total about $31 million of pole, conductor, conduit, and line-transformer costs that were erroneously classified as customer-related using a minimum-system

[19] 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/.

analysis. Dividing by the number of residential bills yields a "customer-related" distribution-grid cost of $19.09 per residential customer.[20]

Q: Why would it be unreasonable for DEP to recover costs through the residential BFC that were classified as "customer-related" using a minimum-system analysis?

A: As discussed in Section III, the $31 million of distribution-grid costs that DEP proposes to recover through the residential BFC 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 BFC 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 – which I do not concede – 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 poles, the same length of conductor) 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.)

[20] Calculated based on data provided in the Company's responses to Vote Solar Data Request Nos. 1-20 and 1-25.

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: Would it be reasonable to recover AMI meter costs through the residential BFC, as DEP proposes?

A: No. Recovering AMI costs through the residential BFC would be inconsistent with cost-causation principles. 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."[21] 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.

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

Within the residential class, high-usage, more-sophisticated energy consumers will likely reap greater benefits than lower-usage customers from AMI technologies and services.[22] In which case, it would be consistent with cost-causation principles for larger users to contribute a greater share toward recovery of AMI costs than smaller users. However, each customer, regardless of usage, would contribute the same amount to recovery of AMI costs if such costs were recovered through the residential BFC. Thus, recovering AMI costs through the residential BFC, as proposed by DEP, would be contrary to cost-causation principles.

In addition, the Company's proposal to recover AMI meter costs through the residential BFC would effectively double-count the cost to meter a new customer since the proposed BFC would recover both the cost of AMI meters and the cost of the legacy meters replaced by AMI meters.

Q: Why is the Company's proposal to recover uncollectible costs through the residential BFC inconsistent with cost-based rate design?

A: Uncollectible costs tend to vary with revenues and thus with usage. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.

Q: Once the excess costs from the minimum-system approach have been removed, what is the resulting cost to connect a residential customer to the distribution grid?

A: As shown in Table 1 below, I estimate that $9.23 per residential customer per month would recover the truly customer-related costs of meters, service

[22] For a description of the expected customer benefits from the Company's investment in AMI meters, see *Direct Testimony of Donald Schneider, Jr. for Duke Energy Progress, LLC*, Docket No. 2018-318-E (November 8, 2018).

drops, and customer services allocated to both the standard-service and time-of-use rate classes.

Q: How did you derive your estimate of the cost to connect a residential customer to the distribution grid?

A: In response to data requests, DEP provided the results from a cost of service study that classifies distribution costs using the Basic Customer method.[23] These results show an allocation to the residential rate classes of about $16.2 million in customer-related costs. I then adjusted this total in order to remove AMI and uncollectible costs for the reasons discussed above. Dividing the net amount of $15.2 million by the number of residential bills yields a connection cost per residential customer of $9.23 per month.

Table 1: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	$16,160,587	1,647,412	$9.81
Less			
AMI Deferral Amortization	$(378,589)	1,647,412	$(0.23)
Uncollectible Expense	$(568,546)	1,647,412	$(0.35)
Total	$15,213,452		$9.23

Q: What accounts for the $19.77 difference between your $9.23 estimate of the residential connection cost and the $29.00 residential BFC proposed by DEP?

A: The $19.77 difference between my $9.23 estimate of the cost to connect a residential customer and the $29.00 BFC proposed by DEP represents load-

[23] DEP responses to Vote Solar Data Request Nos. 1-19 and 1-20.

related 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 Company's proposal to recover $19.77 in load-related costs through the BFC?

A: As I discuss in the following sections, this shift in recovery of load-related costs from the volumetric energy rate to the fixed customer charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.

V. DEP's Proposal to Increase the Residential BFC Would Lead to Intra-Class Cost Subsidization

Q: How would the Company's proposal to increase the residential BFC cause subsidization within the residential class?

A: As discussed above, DEP's proposal to increase the residential BFC would shift recovery of load-related costs from the volumetric energy rate to the fixed customer charge. 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 load-related costs are recovered through the fixed customer charge rather than through the volumetric energy rate, residential customers with below-average usage would bear a disproportionate share of load-related costs and consequently subsidize customers with above-average usage. In other words, a residential customer with below-average usage would pay more, and a residential customer with above average-usage would pay less, than their fair share of such costs.

Q: What is the extent of the intra-class subsidization under the Company's proposal for the residential BFC?

A: As explained above, the $19.77 difference between the $9.23 residential connection cost and the $29.00 residential BFC proposed by the Company represents load-related costs that DEP would inappropriately recover from each residential customer every month through a fixed charge on the customer's bill. The Company estimates about 1.6 million residential bills in the test year.[24] This means that $32.6 million of load-related costs would be recovered annually through the residential BFC under the Company's proposal.[25]

If the load-related costs recovered through the residential BFC under the Company's proposal were instead recovered through the volumetric energy rate, each residential customer would contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about 2.0 million megawatt-hours.[26] Therefore, if the $32.6 million of load-related costs continued to be recovered through the volumetric energy rate rather than through the residential BFC, they would be charged at a rate of 1.61 cents per kilowatt-hour ("¢/kWh").[27] In this

[24] The number of residential bills in the test year is provided in the Company's response to Vote Solar Data Request No. 1-25.

[25] The $32.6 million result is derived by taking the product of the annual number of residential bills (1.6 million) and the amount of the proposed residential BFC in excess of residential connection cost ($19.77 per bill).

[26] Residential sales for the test year are provided in the Company's response to Vote Solar Data Request No. 1-25.

[27] The 1.61¢/kWh result is derived by dividing $32.6 million by residential sales of 2.0 million megawatt-hours.

case, a residential customer with below-average monthly usage of 600 kWh would contribute about $116 per year toward recovery of the $32.6 million of load-related costs while a customer with above-average monthly usage of 1,800 kWh would contribute about $348 per year.[28] 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, under the Company's proposal to recover $32.6 million of load-related costs through the residential BFC, each residential customer would contribute about $237 per year toward recovery of such costs regardless of that customer's usage. A below-average 600 kWh customer would therefore pay more than double their fair share of these load-related costs under the Company's proposal while an above-average 1,800 kWh customer would pay only 68% of their fair share.

Q: Would subsidization of high-usage residential customers by low-usage customers be eliminated if the residential BFC were set at your estimate of the cost to connect a residential customer?

A: No. Even with the residential BFC set at my estimate of residential connection cost, low-usage customers would likely continue to subsidize high-usage customers' costs because customer charges and energy rates are priced at the cost to serve an average-usage customer. For example, 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

[28] Based on data provided in the Company's response to Vote Solar Data Request No. 1-25, I estimate monthly usage of 1,226 kWh for an average residential customer.

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 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. In both 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.

VI. DEP's Proposal to Increase the Residential BFC Would Dampen Energy Price Signals

Q: Would the Company's proposal to increase the residential BFC send appropriate price signals?

A: No. As discussed in Section IV, DEP proposes to set the residential BFC at a rate that greatly exceeds the cost to connect a residential customer to the distribution grid. The amount in excess of residential connection costs represents load-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the cost to connect a residential customer would instead be inappropriately recovered through the fixed customer charge. This shift in the recovery of load-related costs from the volumetric energy rate to the fixed customer charge would dampen price signals and discourage economically efficient behavior by residential customers.

Q: To what extent would the Company's proposal to increase the residential BFC dampen price signals provided by the residential volumetric energy rate?

A: With a fixed amount of revenue requirements to be recovered from the residential class, the higher the residential BFC, the lower the volumetric energy rate, and vice versa. As shown below in Table 2, with the BFC set at $29.00, DEP proposes an average energy rate of 11.23¢/kWh in order to recover the requested allocation of total revenue requirements to Schedule RES customers.[29] If, instead, the BFC were set at my $9.23 estimate of the cost to connect a residential customer, I estimate that the average energy rate for Schedule RES customers would have to be increased to 12.86¢/kWh to recover the same allocated revenue requirement.[30]

Table 2: Schedule RES Energy Rates with Connection-Cost and DEP Proposed BFC (¢/kWh)

	Rate With Connection-Cost BFC	Rate With DEP Proposed BFC	Rate Difference	% Difference
Summer	12.99	11.37	(1.62)	-12.5%
Non-Summer				
First 800 kWh	12.99	11.37	(1.62)	-12.5%
Over 800 kWh	12.49	10.87	(1.62)	-13.0%
Average	12.86	11.23	(1.62)	-12.6%

For the average Schedule RES customer with a monthly usage of 1,218 kWh, the price signal would be provided by the flat rate during the

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[29] Provided in the Company's response to Vote Solar Data Request No. 1-25.

[30] For the purposes of this calculation, I assume the same declining-block rate structure for the block volumetric energy rates in the non-summer months as proposed by DEP.

four summer months and the block rate for the second energy block during the eight non-summer months (applicable to monthly usage in excess of 800 kWh).[31] As shown in Table 2, DEP proposes a rate of 11.37¢/kWh for the summer and 10.87¢/kWh for the second non-summer energy block. With the BFC set at $9.23, I estimate an energy rate of 12.99¢/kWh for the summer and 12.49¢/kWh for the second non-summer block. In other words, DEP is proposing summer flat and non-summer second-block rates that are 1.62¢/kWh, or about 13%, less than what those rates would be if the Schedule RES BFC were set at the cost to connect a residential customer.[32] Thus, the Company's proposal for the Schedule RES BFC would dampen the price signal provided by the volumetric energy rate by about 13%.

Q: How would residential customers likely respond to the reduction in the energy price signal resulting from the Company's proposal for the residential BFC?

A: Since the volumetric energy rate under the Company's proposal for the residential BFC would be lower than the volumetric energy rate with a residential BFC of $9.23, residential customers would likely consume more energy with the Company's proposed BFC than they would with a BFC set at the cost to connect a residential customer. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the Company's proposed residential BFC is

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[31] My estimate of the monthly usage of an average Schedule RES customer is derived from data provided in the Company's response to Vote Solar Data Request No. 1-25.

[32] Weighting by the number of months in the summer and non-summer periods, the average of the summer flat energy rate and the non-summer second-block energy rate would be 11.03¢/kWh with DEP's proposed $29.00 BFC and 12.66¢/kWh with the BFC set at $9.23, for a difference of 12.8%.

lower than the volumetric energy rate with the BFC set at residential connection cost; 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 typically 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 2004 review of 36 articles on residential electricity demand published between 1971 and 2000 reported that, 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.[33]

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[34] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[35]

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

[33] Espey and Espey (2004). Specifically, the review reported 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. The full citation for this study is provided in Exhibit JFW-2.

[34] For the average Schedule RES customer with a monthly usage of 1,218 kWh, that would be either the summer flat rate or the non-summer second-block rate.

[35] The citations for these studies are provided in Exhibit JFW-2.

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 residential volumetric energy rate?

A: From Table 3, it appears that a marginal-price elasticity of –0.3 – that is, a 0.3% decrease in consumption for every 1% increase in price – 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 for the Schedule RES BFC?

A: As discussed above, if the Schedule RES BFC were increased as proposed by DEP, marginal energy rates would be about 13% less than what they would be if the BFC were set at residential connection cost. Assuming an elasticity of –0.3, this 13% reduction in the marginal energy rate would result in an increase in energy consumption of about 4% for the average Schedule RES customer. This means that all else being equal, Schedule RES load after a few years with the $29.00 BFC proposed by DEP would be expected to be about 4% higher than it would have been if the BFC had been set at the cost to connect a residential customer.

VII. Conclusions and Recommendations

Q: What do you conclude with respect to the Company's use of the minimum-system method to classify distribution-grid costs in its COSS?

A: The Commission should reject the Company's reliance on a minimum-system analysis to classify distribution-grid costs in the COSS. This inherently flawed analysis erroneously classifies some distribution-grid costs – a portion of the cost of poles, wires, conduits, and transformers – as customer-related, even though they are in fact driven by usage and therefore properly classified as demand-related. The Company's COSS thereby overstates the amount of customer-related costs appropriately recovered through the residential BFC.

Instead, DEP should classify all such distribution-grid costs as demand-related. Only the costs incurred by DEP to connect customers to the distribution grid – i.e., the cost of meters, service drops, and meter-reading, billing, and other customer-service expenses – should be classified as customer-related. My recommended use of the Basic Customer method aligns with the Company's prior practice and would respect long-standing Commission precedent.

Q: What do you conclude with respect to the Company's proposal to increase the residential BFC?

A: The Company's proposal would inappropriately shift load-related costs from the volumetric energy rate to the fixed customer charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage.

Accordingly, the Commission should reject the Company's proposal to increase the BFC for residential customers. Instead, consistent with enduring cost-causation and rate-design principles, I recommend that the monthly BFC be set at $9.23 per residential customer to reflect the cost to connect a residential customer.[36]

Q: Does this conclude your direct testimony?

A: Yes.

[36] I do not take a position on the Company's proposal to set the Schedule R-TOUD BFC at the Schedule RES BFC plus $2.85 for the cost of a time-of-use meter.

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NO. 2018-318-E

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s/ Stinson Ferguson

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SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

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"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

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