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September 13, 2024

Delivered Electronically to rates@santeecooper.com

Chairman Peter M. McCoy, Jr
Santee Cooper, Rates Public Comments (M301)
P.O. Box 2946101
Moncks Corner, SC 29461

RE: Review of the South Carolina Public Service Authority 2024 Request for Rate Adjustment: **South Carolina Department of Consumer Affairs' Comments**

Dear Chairman McCoy:

Please find enclosed the Department of Consumer Affairs' comments regarding Santee Cooper's proposed rate increase, planned to be implemented in April 2025. Prior to 2004, the Department was the state designated intervenor to represent consumers in utility matters before the Public Service Commission. The legislature restored the Department's ability to intervene in utility matters to advocate for the "interest of consumers" in 2018 with Act 258. With Act 90 in 2021, the legislature provided a role for the Department in this rate study process, allowing the Department to offer comments directly to the Santee Cooper Board of Directors.

The Department interprets "consumer" in accordance with the Consumer Protections Code: South Carolina residents who purchase utility services primarily for a personal, family, or household use. As you will see from our comments, many of the residential-related rate increase issues identified also impact small commercial customers.

Acadian Consulting Group assisted the Department in this rate review process. Acadian has extensive experience in utility ratemaking matters, having participated in over 300 regulatory proceedings across the United States and abroad. Acadian's review focused on cost of service and rate design and many of its comments were formed based on its experience in other jurisdictions.

Throughout this rate review process, the Department had multiple discussions with Santee Cooper representatives. The Department also submitted a document and data request to Santee Cooper. Santee Cooper provided certain responsive documents and directed the Department to public information on the company's website. The Department appreciates the cooperation of Santee Cooper; however, as reflected in the attached document containing the Department's comments, the company has not provided any load curve or bill distribution studies to support its cost of service and rate design. The lack of this supporting data raises concerns about the validity of the proposed changes to the structure of residential rates. If these studies are available, the Department requests they be provided so that it can provide supplemental comments.

Attached to this letter is a presentation regarding the Department's review of Santee Cooper's proposal. The following is a summary of the issues and concerns identified therein.

- The proposed production plant cost allocation relies on methods that are biased and negatively impact low-load factor customers such as residential and small commercial customers.
- The proposed increases in monthly residential customer charges disadvantage low-income customers and do not promote energy efficiency.
- The proposed changes to the Residential General Service ("RG") and Residential Time-of-Use ("RT") rates include weekends and holidays in on-peak periods and could lead to significant bill increases for residential customers.
- The proposed introduction of demand charges to the RG tariff and the proposed changes to current RT tariff Time-of-Use periods could lead to significant rate increases for low-income and fixed-income customers.
- The proposed changes to the RG and RT rates are poorly supported without either detailed rate distribution or load curve data and will potentially lead to ratepayer confusion. Santee Cooper has either not conducted or not provided analyses necessary to support these changes.
- Elements of Santee Cooper's proposed residential rate changes are confusing and will likely result in negative ratepayer reaction. For example, the on-peak demand windows associated with the newly proposed demand charges differ from the newly proposed Time of Use on-peak windows.

Based on these findings, the Department recommends:

- Use of a composite classification factor for production plant, such as the use of an Average and Peak ("A&P") cost allocation method, to allocate fixed production plant costs.
- Withdrawal of the proposed increase in RG and Small General Service ("GA") customer charges as current customer charges for these rates are already some of the highest in the region.
- Withdrawal of proposed changes to the RG and RT tariffs since these changes are based on inadequate information concerning rate impacts to residential ratepayers. The proposed RG demand charges are especially problematic since the proposed $10.03 per kW-month

demand charge could potentially increase electric bills for low- and fixed-income households.

Santee Cooper is likely to implement additional rate increases in the near future. Therefore, it is critically important that Santee Cooper not unfairly burden its residential customers with the current rate increase. Additional potential rate increases include:

- Deferred costs associated with Exceptions to the Rate Freeze provided in the Cook Settlement. The 2023 Compliance Report identified over $206 million in costs related to the Exceptions.
- Disputed allocations of unpaid V.C. Summer debt to Central Electric Power Cooperative
- Costs associated with Santee Cooper's proposed partnership with Dominion Energy to construct a 2,000 MW natural gas generation unit in Colleton County.

The Department appreciates the opportunity to submit these comments. We look forward to presenting them to the Santee Cooper Board and addressing any questions in October. Please let me know if we can provide any additional information in the meantime.

Regards,

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Santee Cooper 2024 Electric System Cost of Service and Rate Design Review

Prepared on behalf of South Carolina Department of Consumer Affairs ("DCA")

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September 13, 2024

Study purpose

The Acadian Consulting Group, LLC ("ACG") has been asked by the Department of Consumer Affairs ("DCA") to review South Carolina Public Service Authority's ("Authority," or "Santee Cooper"), 2024 Electric System Cost of Service and Rate Design published in May, 2024.

The purpose of this analysis is to provide the Authority with a consumer-focused opinion of its proposed rate increase. This analysis reviews Santee Cooper's proposed cost and revenue allocation, and the proposed residential rate design, including the proposal to implement demand charges for residential rates.

This analysis finds that:

- **The proposed cost allocation relies on methods that are biased and negatively impact low-load factor customers such as residential and small commercial customers.**
- **The proposed changes to the Residential General Service ("RG") and Residential Time-of-Use ("RT") could lead to significant bill increases for residential customers.**
- **The proposed increases in monthly residential customer charges disadvantages low-income customers.**

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Section 1: Introduction and Summary of Findings

Overview

Santee Cooper is a state-owned utility established in 1934 to provide electricity and water services across the state of South Carolina.

- On May 24, 2024, NewGen Strategies and Solutions, LLC. ("NewGen"), published a report on behalf of Santee Cooper proposing a system average 4.9 percent ($39.7 million) rate increase effective April 1, 2025. This includes an 8.7 percent ($21.4 million) residential rate increase.
- Santee Cooper's proposed residential rate proposals include:
  1) the creation of new on-peak demand charges for the Company's RG tariff;
  2) new peak/off-peak pricing periods for existing time-of-use ("TOU") customers; and
  3) a $0.50, or 2.6 percent, increase in RG tariff monthly fixed customer charges.
- Santee Cooper's proposed rate change marks its first electric service rate increase since April 2017.

Source: 2024 Electric System Cost of Service and Rate Design Study (May 24, 2024), at pages 1-5.

Revenue requirements

Santee Cooper proposes an **overall $39.7 million, or 4.9 percent**, increase in rates. However, distribution customers will see a $29.5 million, or 6.7 percent, increase, **including a $21.4 million, or 8.7 percent, increase in residential rates**. Meanwhile, industrial customers will see only a $10.2 million or 2.8 percent increase in rates.

	Calendar Year 2025			
Service	Existing Rate Revenue	Proposed Rate Revenue	Proposed Revenue Increase	Percent Rate Increase
	------------------	($000)	------------------	
Residential	$ 245,108	$ 266,508	$ 21,400	8.7%
Commercial	181,521	188,875	7,354	4.1%
Lighting	15,756	16,541	785	5.0%
Total Distribution	**$ 442,385**	**$ 471,924**	**$ 29,539**	**6.7%**
Industrial (Firm & Non-Firm)	361,524	371,689	10,165	2.8%
Total Retail System	**$ 803,910**	**$ 843,613**	**$ 39,703**	**4.9%**

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Overview – Current rates and the Cook Settlement Agreement

Santee Cooper's current rates were designed in December 2015 but suspended for implementation until April 2017. Soon afterwards, Santee Cooper faced a class-action lawsuit on behalf of its customers due, in part, to the cancellation of its nuclear power development activities.

- This lawsuit was settled in March 2020 under the "Cook Settlement Agreement" that includes a retail rate freeze until January 2025 in an attempt to ensure that retail ratepayers do not bear additional costs from the nuclear project.
- The Cook Settlement Agreement required the Authority to forgo the deferral of any costs incurred during or otherwise appropriately attributable to the agreed-upon rate freeze with a few important exceptions.
- The Cook Settlement Agreement notes that cost recovery for these limited exceptions will be through a deferred cost recovery adjustment and are not a part of the proposed rate increase in this proceeding.

Source: Cook v. Santee Cooper, Case No. 2019-CP-23-6675. Information regarding the class action settlement. Available at: https://santeecooperclassaction.com.

Overview – Future Rate Increases

Santee Cooper's proposed 4.9 percent rate increase represents the first of likely several significant rate increases that will occur over the next few years.

- Santee Cooper deferred some costs during the rate freeze (Cook Rate Freeze Exceptions) that will be charged to customers sometime after the end of the rate freeze January 15, 2025.
- Central Electric Power Cooperative Inc., a generation and transmission entity that serves a number of rural cooperative electric utilities, recently aired concerns that it is inappropriately being allocated some costs associated with unpaid V.C. Summer debt to the benefit of retail customers.
- Santee Cooper expressed earlier this year that it desires to partner with Virginia-based Dominion Energy to construct a 2,000 MW natural gas generation unit on the site of a former coal-fired generation unit along the Edisto River in Colleton County.

Source: 2024 Electric System Cost of Service and Rate Design Study (May 24, 2024), pages 5-6; Jessica Holdman (August 20, 2024), "SC-owned power company wants to buy 155 acres in industrial park for 'future generation,' SC Daily Gazette; and John McDermott (August 25, 2024), "SC electric co-ops all charged up over Santee Cooper's $3.6B VC Summer debt," Post and Courier.

DCA findings and residential ratepayer concerns.

DCA's review identifies four residential ratepayer concerns with the Santee Cooper proposed rate increase:

(1) The proposed allocation of costs between customer classes is potentially biased;

(2) The proposed increase in RG tariff customer charges will impact low-income residential customers disproportionately;

(3) The proposed introduction of demand charges to the RG tariff and the proposed changes to current RT tariff TOU periods could lead to significant rate increases for low-income and fixed-income customers; and

(4) The proposed changes to the RG and RT rates are poorly supported without either detailed rate distribution or load curve analyses and will potentially lead to ratepayer confusion.

Cost allocation issues.

The proposed class cost of service study ("CCOSS"), and the Authority's use of this study in allocating costs, employs a method that is biased and negatively impacts low load-factor customers (i.e., residential and small commercial classes) whose electrical use is typically more associated with weather sensitive air conditioning loads relative to larger industrial customers that are less weather sensitive.

A primary methodological flaw with the Authority's CCOSS is its failure to consider the various joint functions that electric systems perform, particularly with regards to the various roles that production plant assets play. Electric generation units ("EGU"), for instance, serve multiple functions in basic load requirements (called "baseload requirements) and peaking requirements that arise during hot summer hours/days. **This methodological flaw over-emphasizes the importance of the peaking function of Santee Cooper's generating units while under-emphasizing the role that these units play in supplying basic electricity to customers.**

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Concerns related to filing – residential rate design

Santee Cooper's residential rate design proposals include:

1) elimination of existing seasonal energy rates and introduction of a proposed demand rate under the RG tariff;
2) changes to the existing RT tariff that includes the timing of on-peak and off-peak rate periods; and
3) a $0.50, or 2.6 percent, increase in RG tariff monthly fixed customer charges.

- Santee Cooper's proposed changes to the RG and RT tariffs, could lead to significant bill increases for residential customers consistent with the experience of other electric utilities around the country.
- Santee Cooper's proposed increase in monthly fixed residential customer charges disadvantages low-income customers since they typically pay a greater percentage of their monthly bill through the fixed customer charge relative to higher-income customers.

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Summary of DCA recommendations.

Cost and Revenue Allocation

- DCA recommends the use of a composite classification factor for production plant, such as the use of an Average and Peak ("A&P") cost allocation method, to allocate fixed production plant costs.

Rate Design

- DCA recommends the Authority withdraw its proposal to increase RG and Small General Service ("GA") customer charges as current customer charges for these rates are already some of the highest in the region.
- DCA also recommends the Authority withdraw its proposed changes to the RG and RT tariffs since these changes are based on inadequate information concerning rate impacts to residential ratepayers.
- The proposed RG demand charges are especially problematic since the proposed $10.03 per kW-month demand charge could potentially increase electric bills for low- and fixed-income households.

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Section 2: Cost Allocation

2.1 Cost of Service Overview

Cost of service methods: overview.

A class cost of service study ("CCOSS") is used to **allocate the total cost of service (revenue requirement) to customer classes**.

Customer classes are determined by **grouping customers with similar cost and usage patterns**. Customers with similar usage characteristics impose similar costs on the utility:

- Size (volume and capacity)
- Type of meter (residential, commercial, industrial)
- Type of usage (space heat, non-space heat)
- Type of load (firm, interruptible)
- Load factor (average usage, peak usage)

Allocation factors are applied and developed by analyzing the relationship (cause and effect) among various cost categories.

Cost of service methods: estimation steps.

Most CCOSS models use a three-part estimation process. This is a process generally followed by Santee Cooper:

Functionalization: The process of dividing the total revenue requirement into functional components as related to utility operations (generation, transmission, distribution).

Classification: The process of separating the functionalized costs into classifications based on the function they serve. Primary cost classification categories:

- Demand-related (capacity-related) – costs that vary with kW of demand
- Energy-related – costs that vary with the kWh of energy
- Customer-related – costs that vary with the number of customers

Allocation: The process of separating the functionalized and classified costs to different customer rate classes.

Allocation factor comparison.

Santee Cooper's proposed CCOSS allocates costs to residential customers in substantially different amounts based on the allocation factor employed.

- **Energy allocation factor** – 31.8 percent of costs allocated to residential customers.
- **Demand allocation factors** – 44.9 to 47.5 percent of costs allocated to residential customers.
- **Customer allocation factors** – 80.9 percent of costs allocated to residential customers.

Santee Cooper's proposed CCOSS relies very heavily on demand and customer allocations, which, as shown above, assigns a greater portion of costs to residential and small commercial customers. This is especially true with regards to allocation of fixed plant costs, which Santee Cooper allocates on the basis of demand allocation factors.

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Energy allocation factors

Santee Cooper allocated fuel expenses and other variable expenses, such as the energy-related share of purchased power costs, on the basis of the relative electricity use between customer classes.

Customer Class	2025 GWh	2025 Percent
Residential	2,071	31.77%
Commercial	1,873	28.73%
Lighting	61	0.94%
Total Distribution	**4,006**	**61.43%**
Industrial (Firm)	2,515	38.57%
Total	**6,521**	**100.00%**

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Demand allocation factors

Most fixed plant costs are allocated by Santee Cooper on the basis of a series of test year demand measured using historical data reported by AMI meters.

- Fixed production and transmission-related costs are allocated based on the average of monthly maximum system coincident peak ("CP") demand;
- Fixed distribution-related costs are allocated based on relative customer class's maximum non-coincident demand ("NCP").

Customer	Production 4 CP		Transmission 12 CP		Distribution NCP	
Class	MW	Percent	MW	Percent	MW	Percent
Residential	575,997	47.48%	500,508	44.93%	478,521	60.15%
Commercial	332,756	27.43%	310,830	27.90%	305,148	38.36%
Lighting	7,819	0.64%	6,789	0.61%	11,904	1.50%
Total Distribution	**916,571**	**75.55%**	**818,127**	**73.44%**	**795,574**	**100.00%**
Industrial (Firm)	296,558	24.45%	295,883	26.56%	N/A	N/A
Total	**1,213,129**	**100.00%**	**1,114,010**	**100.00%**	**795,574**	**100.00%**

Note: "Coincident Peak" ("CP") is a measure of each customer class's demand at the time of Santee Cooper's system peak and not the individual customer class peak demand. The 4 CP measure is the average maximum CP for the months of January, February, July, and August. The 12 CP is the average of 12 monthly maximum CP for all 12 months of the test year. "Non-Coincident Peak" ("NCP") is a demand measure of each customer class's highest electrical demand regardless of relationship to system peak demand.

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Customer allocation factors

Customer-related costs such as costs associated with meters, service drops, and monthly customer billing is allocated by Santee Cooper on the basis of relative numbers of customers and fixtures, with larger customers weighted greater relative to residential customers.

Customer Class	Rate	Customer Delivery Points	Percent	Weight Factor	Weighted Customer	Percent
Residential	RG	182,940	84.90%	1.00	182,940	80.89%
Small General Service	GA, TP	27,762	12.88%	1.30	36,091	15.96%
General Service	GB, GV	2,050	0.95%	2.09	4,279	1.89%
Commercial Lg Demand	GL	38	0.02%	2.09	80	0.04%
Commercial Time of Use	GT	25	0.01%	2.09	52	0.02%
Commercial Traffic Light	TL	305	0.14%	1.00	305	0.13%
Lighting	MS, OL	2,314	1.07%	0.50	1,157	0.51%
Total Distribution		**215,435**	**99.99%**		**224,905**	**99.44%**
Industrial (Firm)		31	0.01%	40.51	1,256	0.56%
Total Retail System		**215,466**	**100.00%**		**226,160**	**100.00%**

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Electric system capital spending

Santee Cooper's demand allocation represents an important concern when reviewing its proposed rate increase because of the Authority's significant recent capital expenditures. Santee Cooper reports a 2024 capital budget of $650 million, including proposed generation or production plant spending of $344 million. Production plant represents 52.9 percent of the Authority's overall 2024 capital spending.

	2024 Capital Budget		
Function		**(Million $)**	**Percent**
Generation	$	344.0	52.92%
Transmission		188.0	28.92%
Distribution		59.0	9.08%
Customer & Corporate Services		59.0	9.08%
Total Capital Budget	**$**	**650.0**	**100.00%**

Source: 2-8 Santee Cooper 2024 Rate Adjustment Request 05.24.2024, Attachment B.

Functionalization of revenue requirements

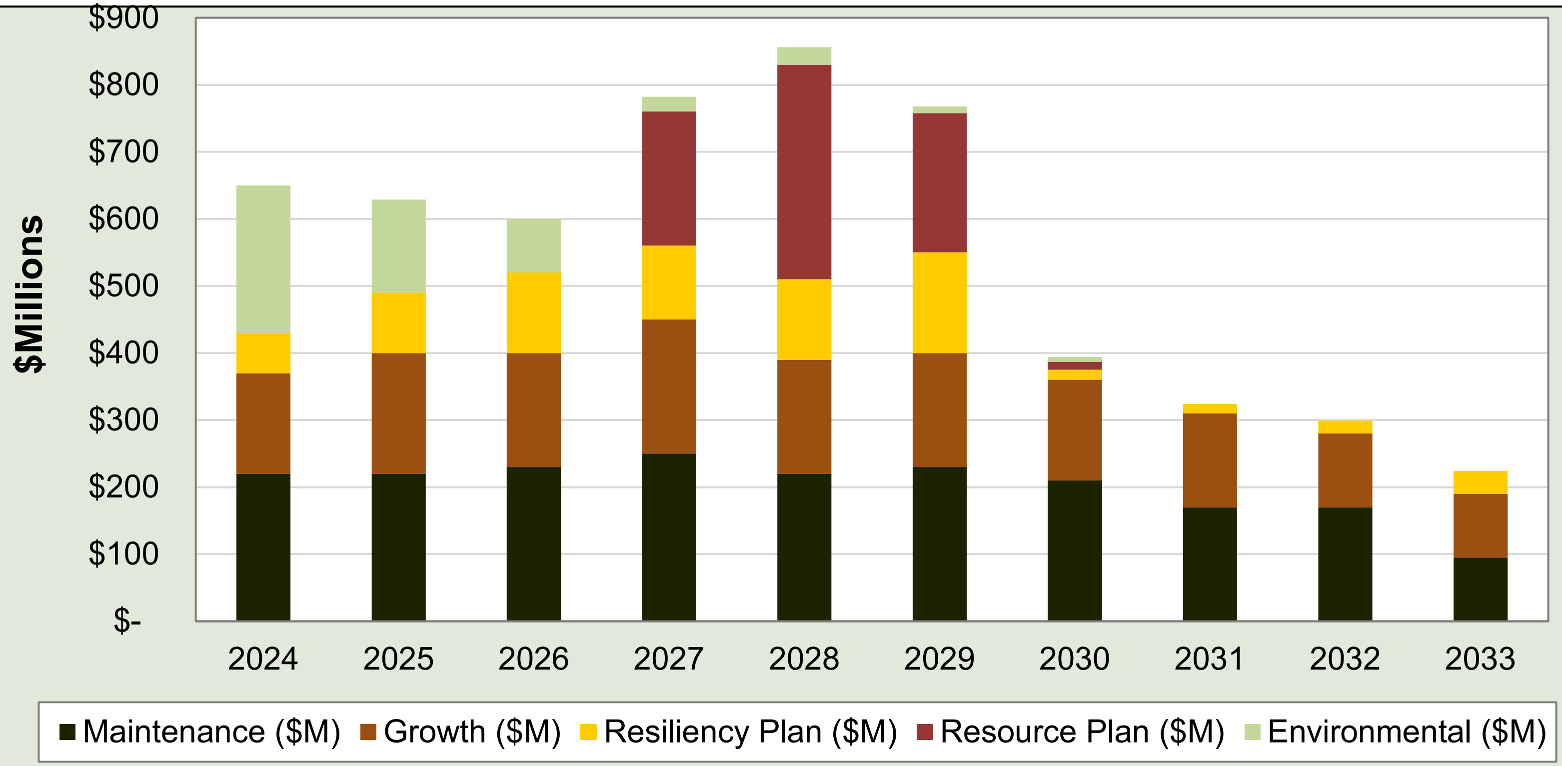
Santee Cooper's significant investment in production plant assets contributes to a significant focus of its overall 2025 test year revenue requirement on supporting the generation function. The Authority estimates that of its test year $843.6 million total revenue requirement, $635.4 million, or 75.3 percent, is associated with the generation function.

Function	2025 Revenue Requirement (Million $)		Percent
Generation	$	635.4	75.31%
Transmission		103.1	12.22%
Distribution		73.2	8.67%
Customer & Corporate Services		32.0	3.79%
Total Retail System	**$**	**843.6**	**100.00%**

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Electric system 10-year capital plan

Ratebase-related costs for Santee Cooper are only expected to grow over time as the Authority forecasts $5.5 billion in new capital spending over the next decade. Average annual growth-related capital investment accounts for 31 percent of total forecast capital spend with as much as 40 percent, on average, dedicated to maintenance related investments.



Source: 2-8 Santee Cooper 2024 Rate Adjustment Request 05.24.2024, Attachment B.

2.2 Production Plant Allocation

Inventory of Santee Cooper EGUs

Santee Cooper owns 5.6 GW of electric generation capacity from a variety of generation sources:

- 331 MWs (5.9 percent of total) from a 1/3 ownership stake in V.C. Summer nuclear generation station;
- 3,530 MWs (22.6 percent of total) from two coal-fired EGUs;
- 1,261 MWs (22.6 percent of total) from natural gas EGUs;
- 199 MWs (3.6 percent of total) from a number of diesel EGUs;
- 233 MWs (4.2 percent of total) from ownership of four hydroelectric dams;
- 30 MWs (0.5 percent of total) from other renewable sources such as landfill gas and solar sources.

Name	In Service Year	Nameplate Capacity (MW)	Percent Total
Nuclear			
V.C. Summer (1/3 Ownership)	**1984**	**331**	**5.9%**
Coal			
Cross	1984-2008	2,380	42.6%
Winyah	1975-1981	1,150	20.6%
Total Coal		**3,530**	**63.2%**
Natural Gas			
Cherokee County Cogeneration	1998	101	1.8%
John S. Rainey Combined Cycle	2001	530	9.5%
John S. Rainey Combustion Turbines	2002-2004	630	11.3%
Total Natural Gas		**1,261**	**22.6%**
Diesel			
Hilton Head	1973-1979	100	1.8%
Honea Path	1979	2	0.0%
Myrtle Beach	1962-1976	85	1.5%
Sediver	2003	2	0.0%
Thermal Kem	2003	2	0.0%
Valenite	2003	2	0.0%
Webb Forging	2003	5	0.1%
Total Diesel		**199**	**3.6%**
Hydro			
Buzzard Roost	1940	7	0.1%
Jefferies Hydro	1942	140	2.5%
Spillway	1950	2	0.0%
St. Stephen	1985	84	1.5%
Total Hydro		**233**	**4.2%**
Renewables			
Bell Bay Solar Farm	2017	2	0.0%
Berkeley Green Power Project (Landfill Gas)	2011	3	0.1%
Horry County (Landfill Gas)	2001-2003	3	0.1%
Jamison Solar Farm	2019	1	0.0%
Lee County Landfill Combustion Turbine	2009	5	0.1%
Lee County Landfill Internal Combustion	2005	5	0.1%
Richland County Landfill Combustion Turbine	2006	5	0.1%
Richland County Landfill Internal Combustion	2010	3	0.1%
Runway Solar Farm	2019	2	0.0%
Total Renewables		**30**	**0.5%**
Total Generation		**5,584**	**100.0%**

Source: S&P Capital, EIA form 923.

Electric generation unit function

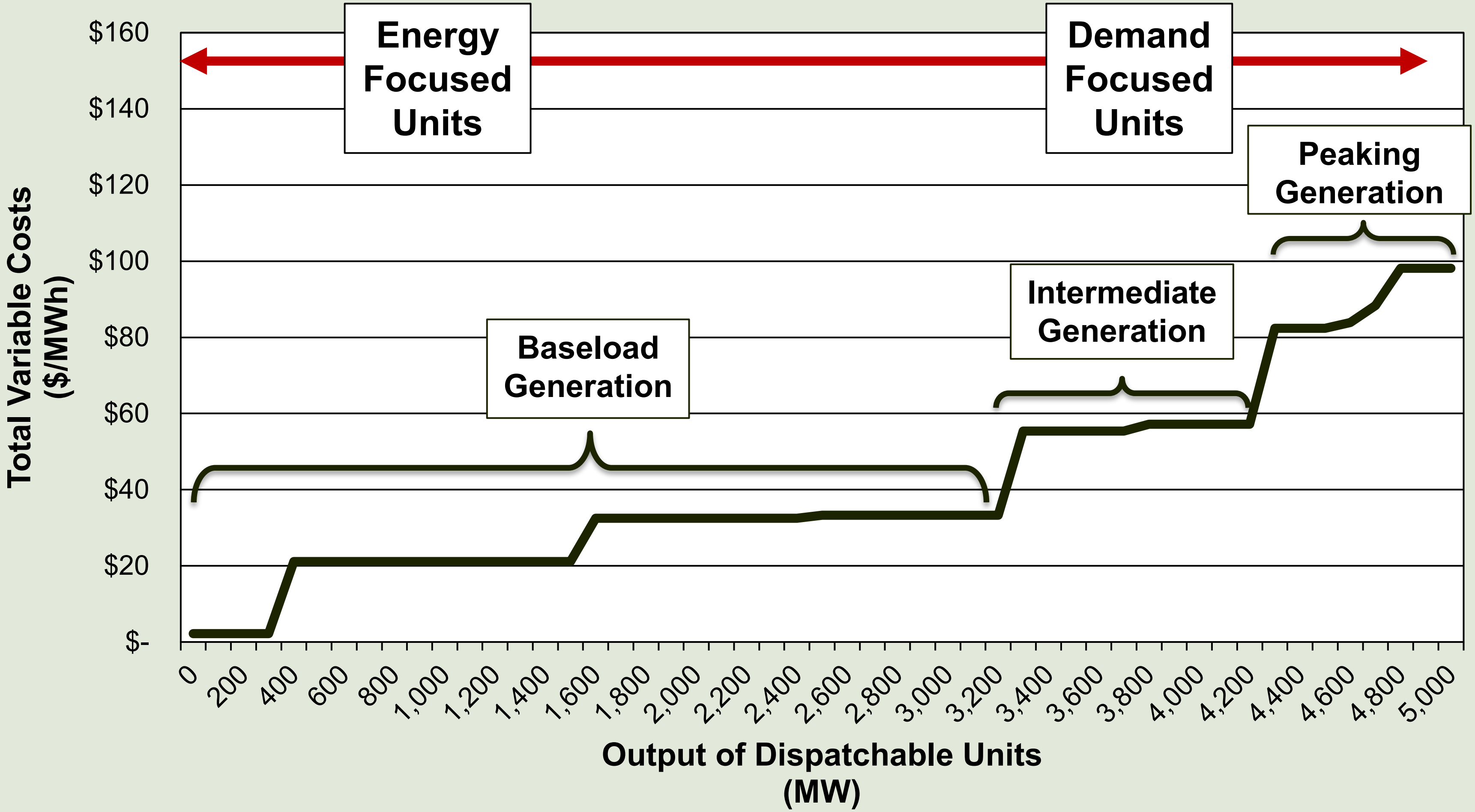
Baseload units: are designed to operate throughout the year to meet a utility's basic generation requirements. These units typically have high installed capital costs, but low operating costs and historically have included nuclear, coal, and hydro-electric units.

Peaking units: are designed to quickly and cost effectively "start-up" to fill temporary shortfalls in generation capabilities. Peaking units are held in reserve and only utilized by a utility during peak, usually weather-driven demand periods when additional generation resources are needed. Natural gas combustion turbines ("CT") typically fulfill these peaking requirements.

Intermediate units: operationally fall between baseload and peaking units that have good cycling capabilities that can ramp up and down or be held in stand-by mode until needed. Intermediate units typically have lower operating costs than peaking units but can have higher capital costs and can include older depreciated former baseload units or natural gas combined cycle ("CC") units.

Utility dispatch curve

EGUs are designed to serve both energy and demand/capacity needs of a utility in a relationship known as a utility's dispatch curve or supply stack.



Source: Author's construct based on Arther Mazer (2007), "Electric Power Planning for Regulated and Deregulated Markets," page 93

Electric generation unit fixed costs

Fixed capital costs associated with large baseload EGUs tend to be much higher than EGUs designed to serve peaking roles despite these units having lower variable operating costs.

For example, a "baseload" nuclear light water reactor, similar to V.C. Summer, is estimated to have fixed capital development costs of $7,782 per kW, while an ultra supercritical ("USC") coal-fired reactor is estimated to have fixed capital development costs of $4,401 per kW.

Alternatively, an industrial frame natural gas CT designed to serve peaking loads is estimated to have far lower capital (development) costs of $801 per kW.

Technology	Region ID SRSE ($/kW)
USC	$ 4,401
USC with 30% CCS	5,511
USC with 90% CCS	7,228
CC—single-shaft	1,235
CC—multi-shaft	1,085
CC with 90% CCS	2,977
ICE	2,200
CT- aeroderivative	1,320
CT- industrial frame	801
Fuel cells	7,271
Nuclear—light water reactor	7,782
Nuclear—small modular reactor	8,164
Distributed generation —base	1,778
Distributed generation—peak	2,126
Battery storage	1,293
Biomass	4,857
Geothermal	NA
Conventional hydropower	5,104
Wind	2,116
Wind offshore	NA
Solar thermal	NA
Solar PV with tracking	1,392
Solar PV with storage	1,781

Source: EIA (AEO 2023), Table 2. Total overnight capital costs of new electricity generating technologies by region.
Notes: Costs are in 2022 dollars per kilowatt. Interest charges are excluded. The costs are shown before investment tax credits are applied. SRSE refers to the Southeast geographic region.

Analysis of 2023 Santee Cooper generation unit capacity factors

Capacity factors are good indicators of EGU roles (baseload, intermediate, peaking). A large share of Santee Cooper's EGUs have high-capacity factors indicating they serve both energy and peak demand requirements. This includes the Company's ownership portion of V.C. Summer, which had an 86.39 percent capacity factor in 2023.

Station Name	Plant Type	Nameplate Capacity (MW)	Net Generation (MWh)	Capacity Factor	Allocation	
					Energy	Demand
Cross	Steam Turbine	2,380.0	8,449,234	40.53%	40.53%	59.47%
Hilton Head	Gas Turbine	100.0	(28)	0.00%	0.00%	100.00%
Jefferies Hydro	Hydraulic Turbine	140.0	247,605	20.19%	20.19%	79.81%
Spillway	Hydraulic Turbine	2.0	11,785	67.27%	67.27%	32.73%
Winyah	Steam Turbine	1,150.0	2,646,676	26.27%	26.27%	73.73%
V.C. Summer (1/3rd)	Nuclear	331.0	2,505,236	86.39%	86.39%	13.61%
John S Rainey	Combined Cycle	1,160.0	3,365,368	33.12%	33.12%	66.88%

The analysis classifies facilities with annual capacity factors less than 10 percent as fully serving the utility's demand requirements, while all other facilities were divided between energy and demand classifications based on the unit's capacity factor.

Source: S&P Capital, EIA form 923.

South Carolina electric utility example: Duke Energy Progress production plant.

An analysis of Duke Energy Progress ("DEP") found that a significant 81.8 percent of DEP's gross plant in service classified as being energy-related, and only 18.2 percent classified as being demand-related.

Station Name	Plant Type	Nameplate Capacity (MW)	2021 Net Generation (MWh)	2021 Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
							---------- ($ Millions) ----------		
Asheville CC	Gas - Combined Cycle	588	3,591,312	69.7%	69.7%	30.3%	$ 744.4	$ 323.3	$ 1,067.7
Asheville Gas Turbine	Gas - Turbine	424	200,431	5.4%	0.0%	100.0%	-	113.0	113.0
Asheville Steam	Steam	0	0				-	-	-
Blewett	Gas - Turbine	70	-147	0.0%	0.0%	100.0%	-	13.6	13.6
Brunswick	Nuclear	2,003	15,468,860	88.2%	88.2%	11.8%	3,755.4	504.3	4,259.7
Cape Fear Gas Turbine	Gas - Turbine	0	0				-	-	-
Cape Fear Steam	Steam	0	0				-	-	-
Darlington	Gas - Turbine	845	3,858	0.1%	0.0%	100.0%	-	92.3	92.3
Blewett Hydro	Hydro	25	105,479	48.2%	100.0%	0.0%	90.4	-	90.4
Tillery Hydro	Hydro	84	188,157	25.6%	100.0%	0.0%	41.4	-	41.4
Walters Hydro	Hydro	108	383,474	40.5%	100.0%	0.0%	70.7	-	70.7
Marshall Hydro	Small Hydro	5	1,116	2.5%	100.0%	0.0%	16.5	-	16.5
Subtotals:							**$ 4,718.9**	**$ 1,046.5**	**$ 5,765.4**
				Production Plant Classification:			**81.8%**	**18.2%**	**100.0%**

Most expensive units

Source: Docket No. 2022-254-E , Direct Testimony of David E. Dismukes, Exhibit DED-3.

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2.2 Production Plant Allocation

South Carolina electric utility example: Dominion Energy production plant.

An analysis of Dominion Energy South Carolina ("DESC") found that as much as 49.7 percent, or nearly half, of its gross plant in service was energy-related and 50.3 percent was demand-related.

Station Name	Plant Type	Nameplate Capacity (MW)	2023 Net Generation (MWh)	Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
Coit #1 Peaking Unit	Gas Turbine	19.64	275	0%	0.00%	100.00%	$ -	$ 3,661,015	$ 3,661,015
Coit #2 Peaking Unit	Gas Turbine	19.64	125	0%	0.00%	100.00%	-	2,818,745	2,818,745
Columbia Energy Center	Combined Cycle	658.7	2,465,905	43%	42.74%	57.26%	141,989,440	190,265,522	332,254,962
Cope	Steam	417.36	1,375,971	38%	37.64%	62.36%	236,596,046	392,060,051	628,656,097
Hagood #4	Gas Turbine	121.89	17,414	2%	0.00%	100.00%	-	21,193,026	21,193,026
Hagood #5	Gas Turbine	27.4	2,655	1%	0.00%	100.00%	-	8,121,427	8,121,427
Hagood #6	Gas Turbine	27.94	3,255	1%	0.00%	100.00%	-	10,245,939	10,245,939
Jasper	Combined Cycle	1081.97	5,323,095	56%	56.16%	43.84%	304,559,710	237,725,249	542,284,959
McMeekin	Steam	293.76	729,071	28%	28.33%	71.67%	57,838,200	146,308,193	204,146,393
Parr #1 & #2	Gas Turbine	0	52	0%	0.00%	100.00%	-	1,408,364	1,408,364
Parr #3 & #4	Gas Turbine	0	147	0%	0.00%	100.00%	-	639,796	639,796
Urquhart	Steam	100	94,760	11%	10.82%	89.18%	23,482,929	193,602,827	217,085,756
Urquhart #1 Peaking	Gas Turbine	19.64	227	0%	0.00%	100.00%	-	2,605,802	2,605,802
Urquhart #2 Peaking	Gas Turbine	16.32	118	0%	0.00%	100.00%	-	1,265,168	1,265,168
Urquhart #3 Peaking	Gas Turbine	16.32	207	0%	0.00%	100.00%	-	3,037,102	3,037,102
Urquhart #4 Peaking	Gas Turbine	58.9	1,303	0%	0.00%	100.00%	-	27,518,010	27,518,010
Urquhart Combined Cycle	Combined Cycle	547.8	1,916,184	40%	39.93%	60.07%	106,895,930	160,805,132	267,701,062
V.C. Summer (2/3rds)	Nuclear	686.4	5,010,472	83%	83.33%	16.67%	1,243,098,474	248,693,529	1,491,792,003
Wateree	Steam	771.8	1,744,006	26%	25.80%	74.20%	261,760,510	753,003,450	1,014,763,960
Subtotals:							**$ 2,376,221,240**	**$ 2,404,978,346**	**$ 4,781,199,586**
					Production Plant Classification:		**49.70%**	**50.30%**	**100.00%**

Most expensive units

Source: Docket No. 2024-34-E, Direct Testimony of David E. Dismukes, Exhibit DED-5.

Production Plant Conclusions

A significant portion of Santee Cooper's generation fleet is devoted to the provision of baseload power, and thus are functionally energy-related.

The Authority's CCOSS fails to consider the function that EGUs serve in providing baseload requirements, by fully classifying all production plant assets as 100 percent demand-related.

- Recent analyses of other SC utilities have found that between 49.7 and 81.8 percent of production plant can be appropriately classified as serving the energy function, and not the demand function.

The Authority's methodological flaw over-emphasizes the importance of the peaking function of Santee Cooper's generating units while under-emphasizing the role that EGUs play in supplying basic electricity to customers.

- This flaw biases CCOSS results against low-load factor residential customers, who account for a greater portion of Santee Cooper's peak demand requirements, while it under-emphasizes Santee Cooper's energy requirements from baseload EGUs.

CCOSS methods for classifying production plant investments.

Two common methods can be employed to classify production plant in a more appropriate fashion that reflects the "dual use" (peak demand and energy/electricity production) of production plant/EGUs.

- **Average and Peak ("A&P")** – is a "composite" allocator based on energy and demand. The first component (the "average" component) is measured by each customer class's relative average hourly energy consumption while the second measures each customer class's relative peak demand contribution. A weighted average is used to develop the composite classification factor. The weights can be determined via judgement or through an empirical measure like a utility's system load factor.
- **Average and Excess ("A&E")** – also uses a "composite" method where the first component is based on each customer class's relative average hourly energy consumption while the second component represents only the energy use during peak system conditions that are in excess of the average component, hence the "excess" component. These components are combined through weightings based on a utility's system load factor.

State utility regulatory decisions: Michigan Public Service Commission

The Michigan Public Service Commission ("MPSC") has recognized that energy loads are an important contributing factor of production plant costs and thus classify a portion of production plant costs as energy-related.

The Commission agrees ... that DTE Electric's production system was not designed and built solely for the purpose of providing capacity for four hours a year. Indeed, if that were the case, DTE Electric's generation asset portfolio would be very different and would certainly include far fewer of the large base load units that comprise much of the company's current fleet. ***Instead of building a system to simply meet demand, the company developed its production plant to both deliver energy and provide capacity at the lowest overall cost to all customers who use the system.*** Thus, DTE Electric's generating system includes a mix of base load plants that were significant investments, but that provide abundant, reliable, and low-cost energy to all customers, and peaking plants, with low fixed production costs and typically higher fuel costs than the base load units. These peaking plants are the units that are used to meet peak demand in the summer months.

Source: In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11 (3) et. seq., with regard to DTE Electric Company. Case No. 17689, Opinion and Order, dated June 15, 2015.

Conclusions and DCA recommendations: CCOSS/production plant allocation

Santee Cooper's proposal disproportionately increases rates for low load factor customers like residential and small commercial customers relative to larger industrial customers.

> ***Santee Cooper proposes a system-wide average rate increase of 4.9 percent. However, residential rates will be increased by 8.7 percent under the proposal while industrial rates will receive a much smaller 2.8 percent rate increase.***

This disproportionate rate increase is driven by the use of a flawed classification methodology that allocates all fixed production plant costs to peak demand factors, without consideration of energy factors associated with these costs.

> ***DCA recommends that the Authority utilize a composite A&P methodology for classifying production plant investments. This method is more appropriate and better reflects the use of production plant and will be less onerous for residential customers.***

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Section 3: Rate Design

Overview

Electric utility rates are typically comprised of three basic elements:

- Fixed monthly **customer charges** sometimes referred to as a basic service charge or a basic facility charge.
- **Energy rates** that are volumetric rates applied toward a customer's monthly energy usage during a billing period, often measured in terms of kWh.
- **Demand rates** are surcharges that are assessed based upon a customer's maximum usage during a billing period, commonly measured in terms of kW for those customers that are demand metered.

Historically, some smaller use customer classes, such as **residential and small commercial classes**, are not demand-metered and thus, only face customer and energy charges. Customers with just customer and energy charges have bills that are based upon what is commonly called a **"two-part tariff"** (e.g., energy and customer charge) whereas large demand metered customers face a **"three-part tariff"** (e.g., energy, customer, and demand charges).

3.1 Customer Charges

Survey of customer charges

The Authority's current monthly fixed residential customer charges are the second highest in the region, being only less than the monthly fixed residential customer charge of Tampa Electric Co. of $21.60. Likewise, the Authority's current monthly fixed small commercial customer charge is the third highest in the region.

Company	State	Residential Customer Charge ($/month)	Residential Ranking	Small Commercial Customer Charge ($/month)	Commercial Ranking
South Carolina Public Service Authority (Current)	**SC**	**$ 19.50**	**2**	**$ 25.00**	**3**
South Carolina Public Service Authority (Proposed)	**SC**	**$ 20.00**	**2**	**$ 26.00**	**3**
Alabama Power Co	AL	14.50	3	50.00	1
Entergy Arkansas LLC	AR	8.40	12	24.25	4
Duke Energy Progress	NC	14.00	4	22.00	6
Duke Energy Progress	SC	11.78	9	14.00	11
Duke Energy Carolinas, LLC	NC	14.00	4	21.00	8
Duke Energy Carolinas, LLC	SC	11.96	8	11.70	14
Florida Power & Light Co	FL	9.55	10	12.68	13
Duke Energy Florida, LLC	FL	12.89	7	16.02	9
Georgia Power Co	GA	13.81	6	36.00	2
Entergy Louisiana LLC	LA	4.46	14	13.39	12
Dominion Energy South Carolina, Inc	SC	9.00	11	22.00	6
Tampa Electric Co	FL	21.60	1	22.81	5
Virginia Electric & Power Co	NC	7.58	13	14.68	10
Peer Group Average		**$ 11.81**		**$ 21.58**	

Source: Utilities' tariffs.

Residential electric rate comparison

Santee Cooper proposes significant changes to its main residential rate tariffs RG and RT. These include:

1) a 2.6 percent increase in the fixed monthly customer charge for the RG tariff;
2) The establishment of an on-peak demand charge for the RG tariff.
3) The elimination of seasonal energy charges for RG and RT tariffs; and
4) Changes to the TOU period for the RT tariff.

Service type	Current Rate	Proposed Rate	Percent Change
Residential General Service (RG)			
Customer Charge	$ 19.50	$ 20.00	2.6%
Summer Energy Charge	0.12	N/A	N/A
Non-Summer Energy Charge	0.10	N/A	N/A
Energy Charge	N/A	0.07	N/A
On-Peak Demand Charge	-	10.03	N/A
Residential Time-of-Use Service (RT)			
Customer Charge	$ 28.00	$ 20.00	-28.6%
Summer On-Peak Energy Charge	0.34	N/A	N/A
Non-Summer On-Peak Energy Charge	0.31	N/A	N/A
On-Peak Energy Charge	N/A	0.32	N/A
Off-Peak Energy Charge	0.06	0.07	11.9%

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Example: Residential electric bill comparison at different usage levels

Analyses of customer charge (basic facilities charge) increases for other utilities have found that these increases significantly impact lower-use customers.

For example, a recent analysis of a proposed rate increase by Avista Corporation in Washington State found that a typical residential household using 945 kWh per month would see a 13.02 percent bill increase while a household using one-third less (630 kWh per month) would see a 15.57 percent increase in overall rates.

	Customer 1 Hypothetical Typical User				Customer 2 One-Third Less Than Typical User				Customer 3 One-Third Greater Than System Average			
Average Usage per Month (kWh)		**945**				**630**				**1260**		
		Rate		Bill Amount		Rate		Bill Amount		Rate		Bill Amount
<u>Utility Charges - Current Rates</u>												
Monthly Basic Facilities Charge	$	9.00	$	9.00	$	9.00	$	9.00	$	9.00	$	9.00
First 800 kWh		0.09		72.77		0.09		57.29		0.09		72.77
800-1,500 kWh		0.11		15.46		0.11		-		0.11		49.11
Over 1,500 kWh		0.13		-		0.13		-		0.13		-
Average Monthly Utility Bill Under Existing Rates			**$**	**97.23**			**$**	**66.29**			**$**	**130.87**
<u>Utility Charges - Proposed Rates</u>												
Monthly Basic Facilities Charge	$	15.00	$	15.00	$	15.00	$	15.00	$	15.00	$	15.00
First 800 kWh		0.10		78.26		0.10		61.61		0.10		78.26
800-1,500 kWh		0.11		16.64		0.11		-		0.11		52.83
Over 1,500 kWh		0.14		-		0.14		-		0.14		-
Average Monthly Utility Bill Under Proposed Rates			**$**	**109.90**			**$**	**76.61**			**$**	**146.09**
Percent Increase from Existing Rates to Proposed Rates				**13.02%**				**15.57%**				**11.63%**

Source: Washington Utilities and Transportation Commission v. Avista Corporation, Dockets UE-240006 and UG-240007 (consolidated), Direct Testimony of David E. Dismukes, Exhibit DED-8.

Residential customer charge – Maryland Public Service Commission

Regulatory commissions have recognized the inherently detrimental effect increased fixed charges have on the promotion of energy efficiency, as reduction in electric use will lead to less bill savings for customers.

For example, in a 2013 review of a rate increase by Baltimore Gas and Electric ("BGE"), the Maryland Public Service Commission recognized the need to allow customers the opportunity to control their monthly utility bills by reducing energy usage.

Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.

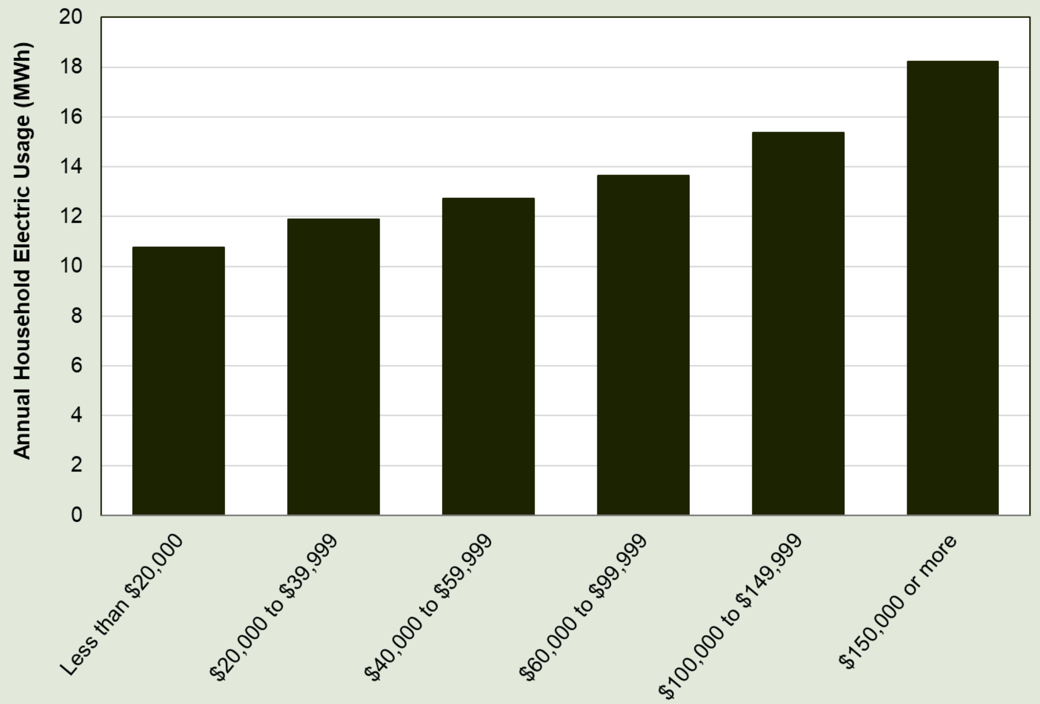
Source: Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (*"Case No. 9299"*). Order No. 85374 at p. 99, rel. February 22, 2013.

High customer charge impacts on lower-income households.

High customer charges discourage energy conservation and shift class revenue recovery responsibilities to lower-use/lower income households.

The Department of Energy reports household usage and income and finds household income is positively correlated with energy consumption in the South region.

For example, households earning less than $20,000 a year consume nearly 41 percent less energy than households earning greater than $150,000 a year.



Source: Energy Information Administration, 2020 Residential Energy Consumption Survey.

Residential customer charge – conclusion

The Authority should withdraw its proposal to increase its residential monthly customer charges from $19.50 to $20.00 per month and small commercial general service customer charge from $25.00 to $26.00 per month.

- Increased customer charges have been shown to disincentivize energy efficiency efforts by reducing the ability of customers to save money on monthly utility bills by reducing electrical usage.
- Increased customer charges have also been shown to disproportionately impact lower income households whose monthly customer charge comprises a greater percentage of monthly utility bills.

Santee Cooper's current residential and small commercial customer charge are among some of the highest in the region, with the Authority's residential customer charge being the second highest and its small commercial customer charge being the third highest. The proposed increases will further this disparity between the Authority's rates and that of other regional electric utilities.

3.2 Residential Rate Changes

Authority's proposed residential demand charges.

Demand charges are designed to recover the costs associated with providing electric service during peak periods and are typically assessed on a customer's highest level of electricity usage.

- Santee Cooper proposes to implement an on-peak demand charge for the RG rate and electric vehicle REV and EVO rates.
- This demand charge will be based on the highest one-hour integrated demand for each customer meter during the monthly on-peak window and purportedly allow for **fixed cost recovery embedded into the energy rate to be recovered in the on-peak demand charge.**

Santee Cooper states that the **recovery of fixed costs through a demand charge** allows for a more equitable alignment between cost-causation and cost-recovery.

- However, this proposal could result in **significant bill increases** if not **communicated appropriately** to customers or based on sound analyses of hourly customer use.

Source: 1.26a Final_Santee Cooper Electric COS Study Report_05.24.24_Appendices A,B.

Authority proposed TOU rate changes.

Authority has proposed changes to the TOU rate structures for both residential and commercial customers. The new TOU periods include summer rates from April through October between 3:00 p.m. and 7:00 p.m., and non-summer rates from November through March between 5:00 a.m. and 9:00 a.m. However, the company has not provided any load curve studies to support these adjustments.

The absence of supporting data **raises concerns about the validity of the proposed changes**.

- Santee Cooper failed to provide DCA an analysis of the distribution of rate impacts on individual customers resulting from the proposed changes in TOU rates and the implementation of demand charges for RG tariff customers.
  - Rate distributions are needed to determine rate impacts on specific customer segments, such as low-income and those on fixed income.
- Santee Cooper also failed to provide DCA a load curve analysis.
  - Load curve analyses are critical for determining whether the new TOU periods reflect actual usage patterns and peak demand times.
  - Without this information, **the fairness and effectiveness of the new rate structures are questionable**.

Example of utility demand charge proposals: Arizona Public Service Company

Arizona Public Service Company ("APS") in a 2017 rate case proposed implementation of mandatory time-of-use or residential demand charges, along with a $5 million education plan to educate customers on the new rates.

- In its education plan, APS promised to notify customers through a variety of channels, including bill messages, web portal, text messages, social media posts, and formal TV and newspaper media.
- A critical aspect of APS' education plan was a focus on potential customer "savings," but did not include specific messages or education content to explain how demand rates worked or how the customer would be affected by the move to demand rates.
- APS's education materials failed to identify if the customer was on the "best plan" based on historical usage.
    - Indeed, after the fact reviews found that 36 percent of APS's residential customer base were moved to rates that were not the most economical rate plan for the customer.

Source: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return thereon, to Approve Rate Schedules Designed to Develop such Return, Docket No. E-01345A-19-0236, Staff Report dated May 19, 2020.

Differing residential load curves

A detailed analysis by APS prior to its implementation of residential demand charges found that **there exists significant heterogeneity in the consumption patterns of residential customers**.

- APS identified **five separate load curves** associated with its residential customers, including **typical weekday evening peakers** (i.e. those customers who have peak demand during evening hours returning from work); **customers with greater daytime peak demand** (i.e. retirees and customers who worked from home); and **twin peakers with significant morning and evening peak demands**.
- APS found that the typical weekday evening peakers **represented only approximately 58 percent** of its residential customers, with **approximately 42 percent of customers** not meeting this typical framework.
- APS also **found less diversity** on holidays and weekends, with most residential customers exhibiting greater daytime peak demand during these periods.

It is important to analyze the impact the proposed implementation of demand charges will have on customers whose load profile differ from typical residential profiles.

- **It is likely that the proposed demand charges will negatively impact customers who rely on electric heating during winter months and thus have high morning energy demands.**
- **It is also possible that the proposed demand charges will negatively impact low-income and fixed-income retirees who have higher daytime loads.**

Source: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return thereon, to Approve Rate Schedules Designed to Develop such Return, Docket No. E-01345A-19-0236, Direct Testimony of David E. Dismukes at 17:6-18.

Confusing nature of proposed residential rate changes.

Elements of Santee Cooper's proposed residential rate changes are confusing and will likely result in negative ratepayer reaction.

- Santee Cooper proposed RG demand charges will only apply to use during an on-peak demand window defined as 3:00-6:00 p.m. during summer months and 6:00-9:00 a.m. during non-summer months.
  - This differs from the newly proposed on-peak energy windows for the RT tariff, which is proposed to be 3:00-7:00 p.m. during summer months and 5:00-9:00 a.m. during non-summer months.
  - It is unclear why the proposed on-peak periods would be different for the RG and RT tariffs would differ if the purpose is to discourage energy use during periods of high electricity prices.
- Santee Cooper proposes to include weekends and holidays in its determination of on-peak energy periods for RG and RT tariff.
  - Weekends and holidays are typically excluded from TOU and time-restricted demand charge structures as residential ratepayers are more likely to be at home during these periods and electrical system resources are less likely to be constrained.

2024 Electric System Cost of Service and Rate Design Study (May 24, 2024), at page 5-2.

Residential rate change conclusions

DCA recommends the Authority withdraw its proposed changes in the current residential RG and RT tariffs.

- **The proposed rates are based on inadequate information** and **does not include rigorous distribution analyses** to assess rate impacts on specific customer segments and load curve studies to compare the proposed rates to hourly wholesale market prices and Santee Cooper's hourly system requirements.
- The Authority should also recognize the significance of its **proposed $10.03 per kW-month demand charge for residential customers**, which could potentially increase utility bills for low-load factor residential customers such as senior citizens living on fixed incomes.

Section 4: Conclusions

Summary of findings.

Cost and Revenue Allocation

- DCA recommends the use of a composite classification factor for production plant, such as the use of an Average and Peak ("A&P") cost allocation method, to allocate fixed production plant costs.

Rate Design

- DCA recommends the Authority withdraw its proposal to increase RG and Small General Service ("GA") customer charges as current customer charges for these rates are already some of the highest in the region.
- DCA also recommends the Authority withdraw its proposed changes to the RG and RT tariffs since these changes are based on inadequate information concerning rate impacts to residential ratepayers.
- The proposed RG demand charges are especially problematic since the proposed $10.03 per kW-month demand charge could potentially increase electric bills for low- and fixed-income households.

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