BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240025-EI

Petition for rate increase
by Duke Energy Florida.
___________________________/

VOLUME 6
PAGES 1106 - 1323

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Wednesday, August 21, 2024

TIME: Commenced: 11:00 a.m.
Concluded: 1:30 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
TALLAHASSEE, FLORIDA
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I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

(Whereupon, prefiled direct testimony of Jeff Pollack was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	DOCKET NO. 20240025-EI Filed: June 11, 2024

CONFIDENTIAL INFORMATION REDACTED

TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	**DOCKET NO. 20240025-EI** **Filed: June 11, 2024**

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GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
2021 Settlement	2021 Settlement Agreement in Docket No. 20210016-EI
AD	Average Demand
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost-of-Service Study
CDM	Cost Duration Model
CS	Curtailable Service
CT	Combustion Turbine
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress
FIPUG	Florida Industrial Power Users Group
Gulf Power	Gulf Power Company
IS	Interruptible Service
ITC	Investment Tax Credit
IOU	Investor-Owned Utility
kW / kWh	Kilowatt / Kilowatt-Hour
MDS	Minimum Distribution System
MFR	Minimum Filing Requirement
MW / MWh	Megawatt(s) / Megawatt-Hour
O&M	Operation and Maintenance

Term	Definition
Proposed Solar Projects	DEF's 14 Proposed Solar Facilities
PTC	Production Tax Credit
ROE	Return on Equity
RRA	Regulatory Research Associates
TECO	Tampa Electric Company
TOU	Time-of-Use

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Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 14323 South Outer Forty Rd., Suite 206N, St. Louis, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science in electrical engineering and a Master of Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in the United States and in several Canadian provinces. This includes frequent appearances in rate cases and other regulatory proceedings before this Commission. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Duke Energy Florida, LLC. (DEF). They consume significant quantities of electricity, often around-the-clock, and require a reliable, affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and substantial interest in the issued raised in and outcome of this proceeding.

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Q WHAT ISSUES DO YOU ADDRESS?

A First, I present an overview of DEF's proposals, including the three proposed test years and the primary cost drivers for the proposed base revenue increases. Second, I address the following specific issues:

- Class cost-of-service study (CCOSS);
- Class revenue allocation; and
- Rate design.

Q ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP?

A Yes. My colleague, Mr. Ly, will address the cost-effectiveness of DEF's 14 "Proposed Solar Projects," including the conditions that the Commission should impose if these projects are approved.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-5**.

Q ARE YOU ACCEPTING DEF'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. In various places, I use DEF's proposed revenue requirement to illustrate certain cost allocation and rate design principles. However, these illustrations, in no way, provide an endorsement of DEF's revenue requirement or any other proposals on issues not addressed in my testimony.

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Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Overview

- DEF is proposing to adjust base rates using three separate, forward-looking, test years. This proposal is unprecedented and overreaching. The Commission has never allowed a utility to propose three consecutive base rate increases in a single proceeding. More typically, base rates have been set for just one test year, while subsequent-year adjustments have been allowed to provide for cost-recovery of specific asset additions that were projected to occur following the rate case test year.
- Setting rates based on three future test years is highly speculative and presupposes that DEF can accurately forecast plant additions, sales, revenues, and expenses nine months before the first set of rates are implemented. However, DEF had to correct an error in its sales and revenue forecasts for each test year, which reduced DEF's proposed revenue deficiency by $53.3 million in 2025. Furthermore, DEF also adjusted its expected retirement date for Steam Anclote Units 1 and 2, reducing depreciation expense by $32 million. These changes clearly demonstrate how even shorter-term projections can be inaccurate.
- The Commission should reject DEF's 2026 and 2027 test years and set rates for just 2025. To the extent DEF has specific asset additions that will be placed in service subsequent to 2025, these additions may be reflected in subsequent-year adjustments, but only if the plant additions have actually been placed in service (*i.e.*, are used and useful) and providing DEF is not overearning.
- DEF's proposed base revenue increase and subsequent-year adjustments are being driven by $2.7 billion of rate base additions and related costs (*i.e.,* operation and maintenance (O&M), depreciation, and property taxes), and higher cost of capital, which is primarily driven by an increase in the return on equity (ROE) from 10.10% under the Settlement Agreement (2021 Settlement) which resolved DEF's last rate case in 2021 to 11.15%.[1]

[1] *In re: Petition for Limited Proceeding to Approve 2021 Settlement Agreement, Including General Base Rate Increases, by Duke Energy Florida, LLC.*, Docket No. 20210016-EI, Amendatory Order, Attachment A 2021 Settlement Agreement at 3-4 (Jun. 28, 2021). See also, *In Re: Petition for Limited Proceeding to Implement Return on Equity Trigger Provision of 2021 Settlement Agreement, by Duke Energy Florida, LLC*., Docket No. 20220143-EI, Order Implementing Duke Energy Florida, LLC's Return on Equity Trigger (Oct. 21, 2022).

- Approximately $1.6 billion of plant additions are for the 14 Proposed Solar Projects. As Mr. Ly testifies, the cost-effectiveness of the Proposed Solar Projects is highly questionable.
- DEF's proposed 11.15% ROE is 137 basis points higher than the 9.78% average ROE authorized by state regulatory commissions nationwide for other vertically-integrated electric investor-owned utilities (IOUs) in rate case decisions in 2023 and through May 2024.
- Florida is viewed as a very constructive regulatory environment for IOUs. Further, a large percentage (52% in 2024) of DEF's annual revenues are collected in various cost recovery mechanisms that allow rates to be adjusted outside of base rate cases. Thus, it is clear that DEF faces significantly less regulatory risk than many of its peer IOUs. Accordingly, the lower regulatory risk should be reflected in the ROE authorized for DEF.

Class Cost-of-Service Study

- DEF is proposing to set rates using a CCOSS that allocates production plant using the Twelve Coincident Peak (12CP)+25% Average Demand (AD) method and transmission plant using the 12CP method.
- Neither the 12CP+25% AD nor the 12CP methods reflect the reality that DEF is largely a summer-peaking utility with an occasional secondary winter peak. The summer and winter peak demands drive the need to install capacity to maintain system reliability.
- 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. If system planners installed capacity sufficient to serve the average of 12 monthly peak demands, DEF would not be able to serve all of its load during the peak periods.
- DEF asserts that allocating 25% of production on AD recognizes the role energy is given in generation facility planning, including DEF's plan to have installed a total of 37 utility scale solar plants through the 2025-2027 test periods. Besides the fact that 25% is arbitrary and unsupported, it is questionable whether the 14 Proposed Solar Projects are cost-effective. Further, solar plants comprise but one component of an integrated generation fleet that is designed to match supply and demand in real time. There is no basis to distinguish how solar plants are allocated to customer classes than any other generating resource.

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- Production and transmission plant and related expenses should be allocated using the Four Coincident Peak (4CP) method. 4CP recognizes that DEF is a summer-peaking utility with a secondary winter peak. The summer months are also when the transmission system experiences its lowest load carrying capability.
- DEF classifies its distribution network system as 100% demand related. However, a portion of the distribution network should be classified as a customer-related cost using a process referred to as Minimum Distribution System (MDS). This is consistent with the principles of cost causation; that is, when DEF installs a distribution network, it does so, in part, to provide the voltage support and the readiness to serve new customers, irrespective of the amount of power and energy they will consume. Thus, MDS better reflects the drivers that cause a utility to incur these costs.
- MDS is an accepted practice. It was approved for both Gulf Power Company (Gulf Power) and Tampa Electric Company (TECO) in their last rate cases. Additionally, TECO is supporting MDS in its pending rate case.
- Production tax credits (PTCs) were allocated in the same manner as plant in service. However, unlike investment tax credits (ITCs), which reduce production capital costs, PTCs are earned for every megawatt-hour (MWh) generated by a DEF-owned solar project. Accordingly, PTCs should be allocated on an energy basis.
- Similarly, investment tax credits were allocated on plant in service, even though these tax credits are applicable only to production plant.
- DEF did not conduct a distribution loss study in this filing. The distribution loss factors for primary service were assumed to be 1% higher than the corresponding transmission losses. All of the residual losses were attributed to secondary distribution.
- DEF used the same loss factors by delivery voltage for both peak demand and energy. However, respecting the laws of physics, peak demand loss factors should be higher than energy loss factors.
- Accordingly, I have replaced DEF's demand and energy loss factors by delivery voltage with the corresponding loss factors developed by TECO in its pending rate case. TECO's loss factors are based on a distribution loss study and, further, the demand loss factors are appropriately higher than the corresponding energy loss factors.

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Class Revenue Allocation

- DEF has followed the Commission's long-standing policy to move all rates closer to cost, subject to gradualism.
- However, DEF ignored the impact of its proposed 25% and 40% reductions in the Demand Credits applicable to Curtailable and Interruptible customers, respectively, in apportioning the proposed base revenue increases. As a result, the base rates for Curtailable and Interruptible customers would more than triple (over 200%) under DEF's proposal. Increases of this magnitude are overly abrupt, thereby violating reasonable gradualism constraints, and would impose an undue burden on these customers.
- The proper application of gradualism is to limit the increase to any customer class to not exceed 1.5 times the system average base revenue increase, and no class should receive a rate decrease.

Rate Design

- DEF is proposing minor updates to the time-of-use (TOU) rating periods, including renaming the "Super Off-Peak" period to Discount period. However, the proposed On-Peak Demand charges do not provide a strong incentive to shift load to lower cost periods because the Mid-Peak Demand charges also apply to demands during both the On-Peak and Off-Peak periods, while the Base Demand charge applies to demand in all hours. Thus, DEF's proposed TOU rates are time-varying in name only.
- The design of DEF's TOU rates is based on a flawed "Cost Duration Model" (CDM). The CDM spreads production/transmission plant-related costs and marginal energy costs to each hour throughout the year. Thus, it identifies the hours when costs are the highest (*i.e.,* On-Peak period) and the lowest (*i.e.,* Discount period).
- However, because the CDM spreads all production/transmission plant-related costs over all 8,760 hours in a typical year, which is contrary to cost-causation principles, the on-peak price signals are significantly diluted.
- The proposed Discount period would provide significantly lower pricing for a very limited period: six hours during the non-winter months and three hours during the winter months. Most customers could not avoid paying On-Peak and Mid-Peak Demand charges, even if they were able to shift most of their work hours to the Discount periods.

- The inability to avoid additional Demand charges would be a major disincentive for large electricity consumers who operate 24x7 to shift load away from high-cost periods.
- TOU rating periods have to be both practical, reflect time-varying costs, and send proper price signals that encourage customers to shift loads to lower-cost periods. DEF's proposed TOU periods do not meet these criteria, and the Commission should require DEF to redesign them.

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2. OVERVIEW

Q HAS DEF IMPLEMENTED BASE RATE INCREASES RECENTLY?

A Yes. DEF implemented three base rate increases pursuant to the 2021 Settlement. The last of these increases was implemented just this year. Over the three years, the cumulative base revenue increase was 8.0%.

Q WHAT BASE RATE INCREASES IS DEF PROPOSING TO IMPLEMENT IN THIS PROCEEDING?

A DEF is proposing three base rate increases as shown in Table 1. Also shown are the three increases from the 2021 Settlement.

Table 1
Revenue Increases
($000)

Year	Amount	Percent
2021 Settlement		
2022	$67,246	2.8%
2023	$48,933	1.9%
2024	$79,199	3.1%
2024 Rate Case		
2025	$594,017	20.4%
2026	$97,678	2.8%
2027	$130,965	3.6%
Total	$822,660	28.3%

Sources:
Docket No. 20210016-EI, Amendatory Order.
Docket No. 20210016-EI, 2021 Settlement Updated C Schedules.
Docket No. 20240025-EI, Schedule E-13a, at 1-3.

As Table 1 demonstrates, the cumulative impact of the three proposed base revenue increases would be approximately $823 million, or 28.3%.

Q WHAT ARE THE PRIMARY REASONS FOR DEF'S PROPOSED RATE INCREASE?

A DEF expects to add nearly $2.7 billion of rate base through 2027.[2] These additions include:

- 14 new solar projects: $1.6 billion;[3]
- 105 MW of two-hour battery energy storage systems: $194 million;[4] and
- Efficiency improvements to DEF's combined-cycle gas turbine (CCGT) fleet: $116 million.[5]

Additionally, DEF is proposing higher depreciation and dismantling expenses and a much higher cost of capital. This includes an increase in ROE from 10.2% to 11.15% ROE.[6] ***The 95-basis points of higher ROE accounts for, about $110 million of the proposed $823 million (three-year) base revenue increase.***

Q WHAT ARE YOUR PRIMARY CONCERNS WITH DEF'S RATE INCREASE PROPOSAL?

A First, DEF's proposal to implement three consecutive base rate increases derived from three separate fully-projected forward test years is unprecedented and overreaching. Second, the Proposed Solar Projects will dramatically increase DEF's rate base, yet

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[2] MFR Schedule B-1 at 1; DEF's 2024 Electric Forecasted Earnings Surveillance Report, Schedule 2 at 1.

[3] Direct Testimony of Vanessa Goff at 4, 10.

[4] Direct Testimony of Hans Jacob at 3, 5, 7.

[5] Direct Testimony of Reginald D. Anderson, Exhibit RDA-4.

[6] Direct Testimony of Adrien M. McKenzie at 3.

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DEF has provided no assurances that the projects will even achieve the projected benefits or that the projected benefits will actually flow-through to customers. Third, DEF's proposed 11.15% ROE is excessive compared to the returns authorized for other vertically integrated electric IOUs in light of the fact that Florida has a much lower-risk regulatory environment than the vast majority of state regulatory commissions.

Proposed Three Test Years

Q ARE DEF'S THREE PROPOSED TEST YEARS CONCERNING?

A Yes. Setting rates based on three future projected test years is highly speculative and presupposes that DEF can accurately forecast plant additions, sales, revenues, and expenses numerous months before the first set of rates are implemented. In fact, an example of why this is problematic has already occurred: DEF prepared its sales and revenues forecast in February and March of 2023, 21 months before the 2025 test year. However, DEF had to correct an error in its sales and revenue forecasts for the 2025, 2026, and 2027 test years, which reduced DEF's proposed revenue deficiency by $53.3 million in 2025, $47.1 million in 2026, and $56.8 million in 2027.[7] In addition, DEF also adjusted its depreciation expense to correct its expected retirement date assumptions for Steam Anclote Units 1 and 2 from 2029 to 2042, thereby reducing depreciation expense by $32 million.[8] These corrections demonstrate how even short-term projections can be inaccurate.

[7] DEF Response to Staff ROG 1-2.

[8] DEF Response to OPC ROG 6-139.

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Q IS THERE ANY PRECEDENT FOR USING THREE FULLY PROJECTED FORWARD-LOOKING TEST YEARS TO SET RATES FOR THREE CONSECUTIVE YEARS IN A SINGLE PROCEEDING?

A No. DEF claims that there is Commission precedent and refers to the 2017 Settlement and the 2021 Settlement, which included multiple year rate increases. While I am not an attorney, the 2021 Settlement specifically and plainly states that neither the Settlement or any of its terms shall have any precedential value.[9] DEF was not able to cite any fully litigated case whereupon three fully projected forward-looking test years were approved by the Commission.

Q IS IT REASONABLE TO SET RATES FOR THREE FUTURE YEARS IN ONE RATE CASE INVESTIGATION?

A No. The Test Year Rule states that:

> (1) At least 60 days prior to filing a petition for a general rate increase, a company shall notify the Commission in writing of its selected test year and filing date. This notification shall include:
>
> (a) An explanation for requesting the particular test period. If an historical test year is selected, there shall be an explanation of why the historical period is more representative of the company's operations than a projected period. If a projected test year is selected, there shall be an explanation why the projected period is more representative than an historical period;[10]

DEF did not provide a comparison of the 2026 or 2027 test years to the 2023 historical test year purportedly explaining why these years are more representative of its operations than the historical test year. Furthermore, comparing a test year that is three or four years past the historical year would be impracticable and unreliable.

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[9] Docket No. 20210016-EI, *Amendatory Order*, Attachment A 2021 Settlement Agreement at 25 (Jun. 28, 2021).

[10] Fla. Admin. Code Rule 25-6.140(1)(a).

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Q WHAT DO YOU RECOMMEND?

A The Commission should reject DEF's 2026 and 2027 test years and set rates for just 2025. To the extent DEF has specific asset additions that will be placed in service after 2025, these additions may be reflected in future subsequent-year adjustments, but only if the plant additions have been placed in service and providing DEF is not overearning.

Proposed Solar Projects

Q PLEASE SUMMARIZE THE PROPOSED SOLAR PROJECTS WHICH ARE DISCUSSED IN DETAIL BY MR. LY.

A The 14 Proposed Solar Projects represent about 1,050 megawatts (MW) of *nameplate* capacity. DEF projects to commission six projects in 2025, four projects in 2026, and the remaining four projects in 2027.[11] DEF estimates that the 14 Proposed Solar Projects (including land) would cost $1,524 per kilowatt (kW). Through 2023, DEF had installed 1,186 MW of solar capacity at an average cost of $1,368 per kW.[12] Therefore, when DEF completes installation of the Proposed Solar Projects, it will have commissioned 2,235 MW (nameplate) of solar projects representing a total investment of over $3.2 billion or $1,441 per kW.

Q WHAT ARE YOUR SPECIFIC CONCERNS ABOUT THE FUTURE SOLAR PROJECTS?

A DEF asserts that the Proposed Solar Projects would save $1.2 billion in fuel costs over

[11] DEF acknowledged during the deposition of its witness Vanessa Goff that some of these projects may be delayed.

[12] S&P Capital IQ; DEF Response to OPC ROG 7-167.

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their expected 30-year lives and generate another $621 million in PTCs.[13] However, Mr. Ly has determined that DEF has overstated the projected fuel cost savings because it has assumed unreasonably high natural gas prices. Further, absent the PTCs, the 14 Proposed Solar Projects would not be cost-effective.

Q WHAT DO YOU RECOMMEND?

A It is essential to condition approval of these projects by imposing a construction cost cap and performance guarantees to ensure that customers actually receive the benefits projected. These recommendations are discussed fully in Mr. Ly's testimony.

Return on Equity

Q WHAT ARE YOUR SPECIFIC CONCERNS WITH DEF'S PROPOSED RETURN ON EQUITY?

A DEF's proposed 11.15% ROE is excessive when compared to the ROEs authorized by state regulatory commissions in rate cases decided in 2023 and 2024 for vertically-integrated electric IOUs. A list of authorized ROEs for vertically-integrated electric IOUs in electric rate cases decided in 2023 and through May of 2024 is provided in **Exhibit JP-1**. As can be seen, the average authorized ROE by state regulators is 9.78% for the period.

Q ARE FLORIDA ELECTRIC IOUS DEMONSTRABLY RISKIER THAN VERTICALLY-INTEGRATED ELECTRIC IOUS IN OTHER REGULATED STATES?

A No. First, the regulatory climate in Florida is very supportive of the Florida electric IOUs which translates into lower risk for investors. This directly reflects the Commission's ratemaking policies, which include the use of forward-looking, future

[13] Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-3.

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test years and multi-year rate plans, timely cost recovery as reflected in both interim rate increases and in the various cost recovery clauses that allow rates to be adjusted outside of a rate case, allowing a return on construction work in progress, and authorizing securitization for storm damage and other major events. These risk-lowering policies are described in a 2021 assessment of Florida regulation conducted by Regulatory Research Associates (RRA) which ranked Florida above 46 other states for investor supportiveness by giving it a score of Above Average/2. RRA stated:

> ***Florida regulation is viewed as quite constructive from an investor perspective*** by Regulatory Research Associates, a group within S&P Global Commodity Insights. In recent years, ***the Florida Public Service Commission has issued a number of decisions, most of which opted multiyear settlements that were supportive of the utilities' financial health***. Florida has not restructured its electric industry, and the state's utilities remain vertically integrated and are regulated within a traditional framework. PSC-opted equity returns have tended to exceed industry averages when established, and ***the commission utilizes forecast test years and frequently authorizes interim rate increases. As a result, utilities are generally accorded a reasonable opportunity to earn the authorized returns.*** In addition, a constructive framework is in place for new nuclear and integrated gasification combined cycle coal power plants that allows a cash return on construction work in progress for these investments outside of the base rate case process. Whether any of the state's electric utilities will proceed with the construction of nuclear power plants in the foreseeable future remains questionable given the challenges such projects posed for utilities in neighboring states in recent years. State law permits the electric utilities to securitize certain nuclear generation retirement or abandonment costs, and one of the state's major companies has done so. ***Mechanisms are in place that allow utilities to reflect in rates, on a timely basis, changes in fuel, purchased power, certain new generation, conservation, environmental compliance, purchased gas and other costs. Additionally, the state has been very proactive in providing utilities cost-recovery mechanisms for costs related to major storms. Additionally, in 2019 the state opted a Storm Protection Plan Cost Recovery Clause that allows utilities to seek more timely recovery of storm hardening investments outside a general rate case.*** RRA currently accords Florida regulation an Above Average/2 ranking. (Section updated 4/29/21)[14] (emphasis added)

[14] RRA Assessment of the Florida Public Service Commission.

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The Commission's ranking remains at Above Average/2.[15] Only one state regulatory commission, Alabama, is ranked higher than the Florida Commission.

Q WHAT PERCENTAGE OF DEF'S REVENUES ARE SUBJECT TO RECOVERY UNDER THE VARIOUS COST RECOVERY MECHANISMS AUTHORIZED BY THE COMMISSION?

A As can be seen in Table 2, DEF collected 53% of its annual sales revenues from under each of the five currently-effective cost-recovery mechanisms in 2023, and projects it will continue to collect between 44% and 52% in years 2024 and 2025.

Table 2
Percent of Revenues Collected Under the Various Commission-Approved Cost Recovery Mechanisms

Mechanism	2023	2024	2025
Fuel	36%	41%	34%
Energy Efficiency	2%	2%	2%
Capital Cost Recovery	7%	5%	2%
Storm Protection	2%	2%	5%
Storm Cost	6%	2%	-
Total Cost Recovery	53%	52%	44%

Source: MFR Schedule C-2.

Q IS THERE ANY APPRECIABLE REGULATORY LAG IN BASE RATE CASES?

A No. There is no appreciable regulatory lag in setting base rates. The Commission is required to render a decision within eight months after a base rate case is filed. However, because the Commission has authorized the use of a fully projected future test year, the rates approved by the Commission and placed in effect during the test

[15] RRA Regulatory Focus, RRA State Regulatory Evaluations – Energy at 5 (Mar. 1, 2024).

year will exactly recover the projected test-year cost to serve – unless, of course, actual sales, investment, and expenses vary from the utility's projections. Further, the Commission has consistently allowed utilities to propose subsequent-year adjustments that provide for cost recovery of specific assets placed in service after the rate case test year. Thus, there is virtually no regulatory lag in recovering the costs of future plant additions.

Q WHAT DOES THE ABSENCE OF ANY APPRECIABLE REGULATORY LAG MEAN IN SETTING AN AUTHORIZED RETURN ON EQUITY FOR DEF?

A The absence of any appreciable regulatory lag in setting base rates also reduces DEF's regulatory risk. This, coupled with this Commission's other supportive ratemaking policies (*i.e.,* future test year, the ability to adjust rates outside of a base rate case through separate cost recovery mechanisms) demonstrate how DEF's regulatory risk is no higher (and arguably lower) than most other regulated vertically integrated electric IOUs. Therefore, the lower regulatory risk should translate into a lower ROE than the other electric IOUs regulated by less supportive commissions.

3. CLASS COST-OF-SERVICE STUDY

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each customer class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups, or classes. Most of a utility's costs are incurred to jointly serve many customers, therefore the CCOSS provides a mechanism for allocating the utility's costs to customers in a reasonable way based on cost-causation. For purposes of rate design and revenue allocation, customers are grouped into homogeneous customer classes according to their usage patterns and service characteristics. A more in-depth discussion of the procedures and key principles underlying CCOSSs is provided in **Appendix C**.

Q HAS DEF FILED ANY CLASS COST-OF-SERVICE STUDIES IN THIS PROCEEDING?

A Yes. DEF filed CCOSSs for each of the three proposed test years utilizing two different methodologies. DEF's preferred study uses the Twelve Coincident Peak (12CP) and 25% Average Demand (AD) cost allocation method (*i.e.,* 12CP+25% AD).[16] DEF also filed a CCOSS using the 12CP and 1/13th AD (*i.e.,* 12CP+8%) method.[17]

Q SHOULD EITHER OF THESE STUDIES BE USED TO SET CLASS REVENUE REQUIREMENTS IN THIS CASE?

A No. DEF's filed CCOSSs are flawed and cannot be used to determine class revenue requirements.

[16] Direct Testimony of Marcia J. Olivier at 35.

[17] *Id.*

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Q WHAT ARE THE FLAWS WITH DEF'S CLASS COST-OF-SERVICE STUDIES?

A The flaws are:

- First, the 12CP+25% AD method is not consistent with cost-causation principles because it allocates costs to all hours of the year. Further, it is based on an unspecified and subjective assessment of the purported benefits associated with more capital intensive (solar) plants and a flawed and incomplete application of Capital Substitution theory. Capital substitution erroneously assumes that the sole purpose of more capital-intensive power plants is to lower fuel costs, rather than meet expected peak demand. Further, the same theory is not applied to the allocation of fuel costs and, thus, it suffers from a lack of fuel symmetry. 12CP+25% AD also suffers from double-counting. For these reasons, many state regulatory commissions, including Florida, have rejected allocation methods similar to 12CP+25% AD.
- Second, transmission demand-related costs were allocated to customer classes using the 12CP method. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. DEF, however, is a strongly summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.
- Third, DEF failed to recognize that a portion of the distribution network is a customer-related cost. This failure stands in stark contrast to the practices of DEF's affiliates in both North and South Carolina that specifically recognize a customer-related portion of distribution network costs, a practice that is both accepted and consistent with cost-causation principles.
- Fourth, DEF allocated PTCs and ITCs on plant in service. However, PTCs are earned for every MWh generated by a solar project. Thus, they would be more appropriately allocated on an energy basis. ITCs are available only for certain production assets. Accordingly, ITCs should be allocated the same as production plant.
- Finally, the demand and energy losses used in DEF's CCOSS are not based on an actual distribution loss study. DEF derived the distribution loss factors using meter adjustments, which understate the distribution losses. Further, DEF assumed that the demand and energy losses are the same. Reflecting the laws of physics, demand losses should be higher than energy losses.

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Q HOW SHOULD THESE FLAWS BE CORRECTED?

A First, production and transmission demand-related costs should be allocated to customer classes using the 4CP method. The 4CP method is based on demands that occur coincident with DEF's summer period (June through September) demands.

Second, a portion of DEF's distribution network should be considered a customer-related cost, rather than 100% demand, as is consistent with the MDS methodology.

Third, PTCs should be allocated on an energy basis, and ITCs should be allocated on production plant.

Fourth, to provide a proper representation of both demand and energy losses by delivery voltage, I replaced DEF's loss factors with the demand and energy loss factors used by TECO in its pending rate case.

Production Plant

Q HOW IS DEF PROPOSING TO ALLOCATE PRODUCTION PLANT AND RELATED EXPENSES TO RETAIL CUSTOMER CLASSES?

A DEF recommends using an energy-based cost allocation methodology. Specifically, Ms. Olivier recommends the 12CP+25% AD method. Under 12CP+25% AD, production plant and related expenses would be allocated 25% to average demand and 75% to 12CP. Average demand, however, is the same as a pure energy allocator. Further, the 12CP method spreads costs to all twelve months. Thus, DEF's 12CP+25% AD method allocates DEF's production capacity costs on power and energy usage throughout the year.

Q WHY DOES DEF PROPOSE ALLOCATING 25% OF DEF'S PRODUCTION PLANT ON A PURE ENERGY BASIS?

A DEF witness Marcia Olivier asserts that the 12CP+25% AD method recognizes the role energy is given in generation facility planning. She cites the 23 DEF utility scale solar plants in service by December 2024 and DEF's plans to install 14 additional solar facilities in the 2025-2027 test periods.[18] She states these (and other DEF baseload generation) projects:

> …have a higher up-front capital cost, but the benefits to customers are primarily related to the cost of fuel, which is apportioned on an energy basis. Therefore, a larger portion of the Company's production capacity costs should be apportioned in the same manner as the customer realizes the benefits, *i.e.*, on an energy basis. [19]

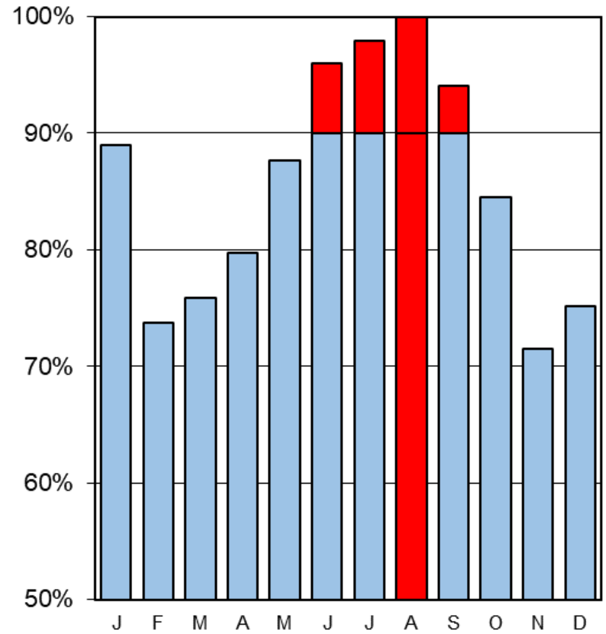
Q DO YOU AGREE WITH HER ASSERTION?

A No. First and foremost, the use of 12CP to allocate costs to a utility that has strong summer and winter peak demands is contrary to cost causation. The seasonal peak demands are summarized in Figure 1 on the following page. Figure 1 clearly demonstrates that DEF's loads are highly seasonal. 12CP would only be appropriate if DEF's loads were relatively flat and/or non-seasonal. The specific problems with 12CP are discussed later.

[18] *Id.* at 36.

[19] *Id.*

Figure 1
Monthly Peak Demands as a Percent of
The Annual System Peak: 2020 – 2025



Second, in stark contrast to peak demand methods (such as 1CP, 2CP, 4CP, and to a much lesser extent, 12CP), the 12CP+25% AD method is not consistent with cost-causation principles. Further, Ms. Olivier's assertion that DEF's production plant is caused by energy consumption is both misleading and inaccurate.

Third, unlike baseload (combined cycle gas turbine) plants, DEF's solar plants can operate only on sunny days. They are not physically capable of serving load in any given hour. Whereas DEF's combined cycle gas turbine plants have operated at capacity factors ranging from 35% to 75% over the past five years, DEF's solar plants have operated at less than a 28% capacity factor.[20] Thus, while solar plants are capital intensive, it is improper to characterize them as baseload energy resources. At best, solar plants are an intermittent energy resource.

[20] S&P Capital IQ.

Fourth, based on the information provided in Exhibit BMHB-3, although DEF projects that these projects will produce fuel cost savings, the DEF solar projects are only cost-effective when factoring in the taxpayer subsidized PTCs. Stated differently, but for the PTCs, the 14 Proposed Solar Projects would not be cost-effective. However, PTCs are effective only during the first 10 years of commercial operation. Once the PTCs have expired, the costs of the solar projects will likely exceed the benefits over their 20-year remaining lives.

Fifth, though unstated in Ms. Olivier's testimony, the only differences between baseload and peaking capacity are the investment and fuel costs. Baseload units have higher investment per kW of capacity and lower fuel costs per MWh produced than peaking units. In other words, Ms. Olivier theorizes that DEF's baseload plants are justified by their lower energy costs rather than their ability to meet peak demand. This theory is referred to as Capital Substitution. However, Ms. Olivier never cites to any planning studies that support the assumption that the investment in baseload capacity is caused primarily by year-round energy usage. In fact, Capital Substitution is a gross oversimplification of utility system planning principles.

Q DO AFFILIATES OF DEF USE THE 12CP+25% AD METHOD TO ALLOCATE PRODUCTION PLANT COSTS TO RETAIL CUSTOMER CLASSES?

A No. For example, in the most recent rate cases in North Carolina, DEF affiliates – Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) – used the Average and Excess method. In South Carolina, although DEP and DEC used the 12CP method to allocate production plant, they did not classify or allocate any production plant costs to energy as DEF is proposing.

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Q DO THE DEF AFFILIATES OPERATING IN NORTH AND SOUTH CAROLINA FACE A MUCH DIFFERENT PLANNING ENVIRONMENT THAN IN FLORIDA?

A No. Both DEP and DEC have been retiring older fossil fuel plants and installing new natural gas combined cycle gas turbine (CCGT) plants, while also building out the infrastructure to support renewable energy projects.

Q HOW IS MS. OLIVIER'S CAPITAL SUBSTITUTION THEORY AN OVERSIMPLIFICATION OF UTILITY SYSTEM PLANNING PRINCIPLES?

A Capital Substitution overlooks four realities:

- The need for new capacity is driven by both projected peak demands and reserve requirements to ensure that electricity is reliable. Using 12CP to allocate the portion of production plant that Ms. Olivier considers to be demand related does not recognize the peak demands that drive capacity needs. Moreover, allocating the remainder of production plant based on energy ignores the important role of load-following capabilities.
- Fuel savings are not a cost driver. All new plants save fuel costs due to improvements in generation technology, not because they are more capital intensive. Although the choice of plant technology is determined by economics, the objective is to provide reliable service at the lowest overall cost — not solely to lower fuel costs.
- CCGTs have become the technology of choice, not because they have lower fuel costs, but because they can provide flexible load-following capabilities needed to balance loads and resources in real time and meet operating reserve requirements. These capabilities are essential to keeping supply and demand in constant balance, particularly as more intermittent resources are added to the system.
- An energy allocation assumes all hours are critical to the choice of generation. However, capacity factor, which measures how often a power plant is dispatched to produce energy, does not determine the type of capacity to install. Thus, allocating investment to all hours is contrary to cost causation.

C31-3108

Q HOW IS ALLOCATING INVESTMENT TO ALL HOURS CONTRARY TO COST CAUSATION?

A The following simplified example demonstrates how an energy allocation is contrary to cost causation. Let us suppose two drivers need to lease cars from a fleet that contains only two types of cars, "**Car P**" and "**Car B**":

	Car P	**Car B**
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high gas mileage (like a baseload plant), while **Car P** has a low fixed charge but gets poor gas mileage (like a peaker). The breakeven cost is 1,000 miles; that is, it would cost $1,000 to drive either car 1,000 miles. However, **Car B** would be less expensive if driven more than 1,000 miles. In fact, **Car B** would be less expensive whether the total driving distance was 1,500 miles, 3,000 miles, or 4,500 miles, etc. In other words, beyond 1,000 miles, total mileage driven would not be a factor in deciding whether to lease **Car P** or **Car B**.

Q HOW IS THIS EXAMPLE RELEVANT TO MS. OLIVIER'S COST ALLOCATION METHODOLOGY?

A Ms. Olivier's cost allocation methodology assumes that all energy production matters; that is, the higher the capacity factor, the larger the portion of investment that should be allocated on a pure energy basis. This ignores the reality that the breakeven capacity factor between baseload and peaking plants likely occurred at a much lower (less than 10%) capacity factor. Thus, the baseload plants would be the lowest cost alternative if they are expected to operate at any capacity factor above the breakeven

C31-3109

capacity factor. Whether a baseload plant operates at a 40%, 60%, or 80% capacity factor would not alter the decision. Thus, the operating capacity factor is irrelevant.

Q HAS THIS COMMISSION PREVIOUSLY REJECTED A PRODUCTION COSTING METHOD THAT ALLOCATES COSTS BEYOND THE BREAKEVEN POINT?

A Yes. This Commission has previously rejected the Equivalent Peaker method because it "…implies a refined knowledge of costs which is misleading, particularly as to the allocation of the plant costs to hours past the break-even point.[21]

Q HAS MS. OLIVIER FULLY APPLIED THE CAPITAL SUBSTITUTION THEORY ON WHICH HER 12CP+25% AD METHOD IS BASED?

A No. The 12CP+25% AD method only partially recognizes the trade-off between capacity and energy. It ignores the fuel benefits that higher load factor customers bring to the system. In other words, if an allocation methodology is selected where high load factor customers are allocated a significant amount of production capacity investment based on their energy consumption, they should also receive a correlating benefit from the lower variable fuel costs incurred during off-peak periods. In other words, the 12CP+25% AD method suffers from a fuel symmetry problem.

Q HAVE OTHER STATE REGULATORY COMMISSIONS RECOGNIZED THE FUEL SYMMETRY PROBLEM ASSOCIATED WITH METHODOLOGIES SUCH AS THE 12CP+25% AD METHOD?

A Yes. The fuel symmetry problem was one of the primary reasons cited by the Public

[21] *In Re: Petition of Gulf Power Company for an Increase in its Rates and Charges*, Docket No. 891345-EI, Order Granting Certain Increases at 48 (Oct. 3, 1990).

Utility Commission of Texas in rejecting every type of energy-based allocation method proposed in rate cases throughout the 1980s and 1990s. In one such case the Commission adopted the Examiner's Report which cited the lack of fuel symmetry in rejecting capital substitution, an energy-based allocation method. Specifically:

> The examiners find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal…the high load factor classes, which will bear higher cost responsibility for base load units, will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units.[22]

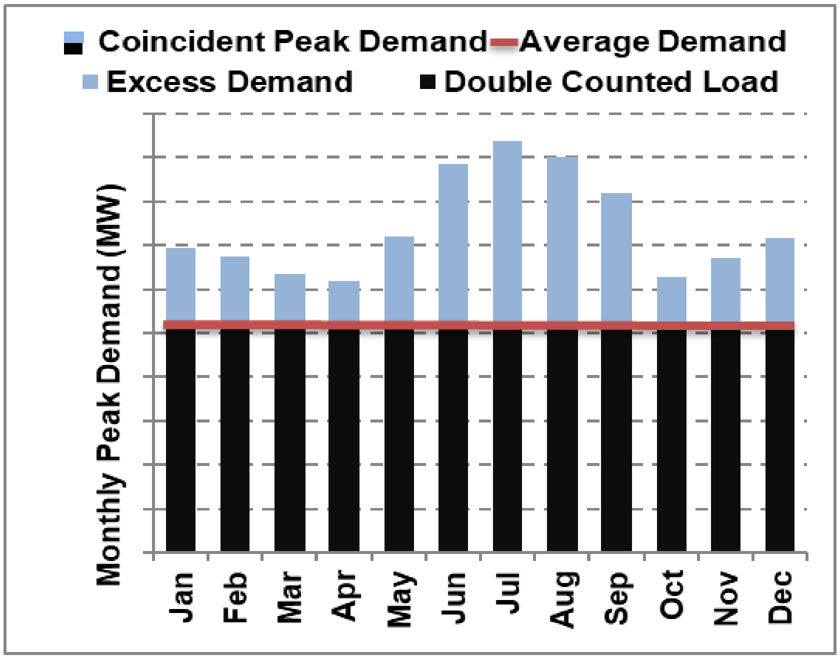
Q ARE THERE ANY OTHER FLAWS WITH THE 12CP+25% AD METHOD?

A Yes. The 12CP+25% AD method also suffers from a "double-counting" problem. Double-counting can occur when plant-related costs are allocated partially on a CP basis and on an average demand (or energy) basis. Average demand is annual energy consumption divided by 8,760 hours. It is also a component of coincident peak demand. This is illustrated in Figure 2 on the following page for a hypothetical summer-peaking utility.

[22] *Application of El Paso Electric Company for Authority to Change Rates and Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit 2*, Docket Nos. 7460 and 7172, Examiners Report at 238, which was opted by Final Order (Mar. 30, 1988) and largely unchanged (and not at all in respect to the reference herein) by the Order on Rehearing (May 10, 1988) and Second Order on Rehearing (Jun. 16, 1988).

C31-3111

Figure 2
12CP+25% AD Method



Average demand is equivalent to the black shaded area of the chart. Peak demand is represented by the combined black and blue shaded areas. In other words, the combination of average demand and 12CP demand allocators used in the 12CP+25% AD method results in double-counting energy usage: once in the average demand allocator and a second time in determining each class's 12CP demand.

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED BY OTHER STATE REGULATORY COMMISSIONS AS A CRITICAL FLAW IN ENERGY-BASED ALLOCATION METHODOLOGIES?

A Yes. For example, both the Iowa Utilities Board and the Public Utility Commission of Texas have cited the double-counting problem in numerous cases. Specifically, the Public Utility Commission of Texas states:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50 percent of the intermediate demand, includes within it an energy component. Dr. Johnson has elected to use a 4 CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and thus "double dipping" is taking place.[23]

Q WHAT DO YOU RECOMMEND?

A The Commission should reject the 12CP+25% AD method because it is not consistent with cost causation, it is an oversimplification of utility system planning principles, and it suffers from the fuel symmetry and double-counting problems as described herein. By allocating demand-related costs primarily based on energy, thereby over-allocating costs to energy-intensive customer classes, such an approach would also have negative impacts on competitiveness and economic development.

Transmission Plant

Q HOW IS DEF PROPOSING TO ALLOCATE TRANSMISSION PLANT AND RELATED COSTS?

A DEF uses 12CP to allocate transmission plant.

Q WHAT ARE YOUR CONCERNS WITH THE 12CP METHOD?

A As previously noted, 12CP gives approximately equal weighting to the power demands that occur during each of the 12 monthly system peaks. In other words, 12CP assumes that the demands occurring in the spring and fall months are as critical to system reliability as meeting summer period demands. Thus, giving substantial

[23] *Id.* at 236.

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weighting to the non-summer months in allocating production and transmission costs ignores the reality that DEF is a strongly summer-peaking utility. This is demonstrated in **Exhibit JP-2**.

As can be seen, there are substantial differences in DEF's monthly system peak demands. Historically, the demands during the summer months have consistently been much closer to the annual system peak than the peak demands in the non-summer months.

Q IS DEF PROJECTING TO REMAIN SUMMER PEAKING?

A No. DEF is currently projecting a winter peak.[24]

Q IS THERE AN AUTHORITY THAT SUPPORT YOUR OPINION THAT 12CP IS NOT AN APPROPRIATE METHOD FOR DEF?

A Yes. The National Association of Regulatory Utility Commissioners' cost allocation manual states:

> This [the 12CP] method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky.[25]

Clearly, DEF's annual load shape is spiky and its monthly peaks do not lie within a narrow range. This was demonstrated in **Figure 1** and **Exhibit JP-2**. Accordingly, 12CP does not reflect cost causation.

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[24] DEF's Amended Ten-Year Site Plan 2024 – 2033 at 2-15 and 2-18 (Apr. 22, 2024).

[25] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 46 (Jan. 1992).

C31-3114

Q WHAT ALLOCATION METHOD WILL RECOGNIZE THESE REALITIES?

A The 4CP method better reflects the realities that DEF has been a strongly summer-peaking utility with a growing winter peak. The peak demands during these periods are more critical to maintaining the reliability of the bulk power system.

Q WHAT DO YOU RECOMMEND?

A The Commission should require DEF to adopt the 4CP method to allocate production and transmission plant and related costs. Recognizing the increasing importance of the winter peak, the 4CP method should include the months January, June, July, and August.

Distribution Network Costs

Q WHAT ARE DISTRIBUTION NETWORK COSTS?

A The electric distribution network consists of DEF's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Account Nos. 364, 365, 366, 367 and 368.

Q HOW IS DEF PROPOSING TO CLASSIFY AND ALLOCATE DISTRIBUTION NETWORK COSTS?

A DEF is proposing to classify all distribution network costs as demand related.

Q IS IT REASONABLE TO CLASSIFY ALL DISTRIBUTION NETWORK COSTS TO DEMAND?

A No. As further discussed below, classifying a portion of the distribution network as a customer-related cost is consistent with the principles of cost causation; that is, it better reflects the factors that cause a utility to incur these costs.

C31-3115

Q WHAT FACTORS CAUSE A UTILITY TO INVEST IN AN ELECTRIC DISTRIBUTION NETWORK?

A The purpose of the electric distribution network is to deliver power from the transmission grid to the customer, where it is eventually consumed. Thus, the central roles of the distribution network are to:

- Provide access to a safe, delivery-ready power grid (*i.e.*, a customer-related cost); and
- Meet customers' peak electrical power needs (*i.e.*, a demand-related cost).

Providing access to a safe, delivery-ready power grid requires not only a physical connection that meets all construction and safety standards, but also the voltage support, which is provided by the distribution network infrastructure. Clearly, these costs are related to the existence of the customer. This is why classifying a portion of the distribution network as customer-related is consistent with cost causation. In other words, investments that must be made solely to attach a customer to the system are clearly customer-related. These customer-related costs should be allocated based on the number of customers served rather than on peak demand.

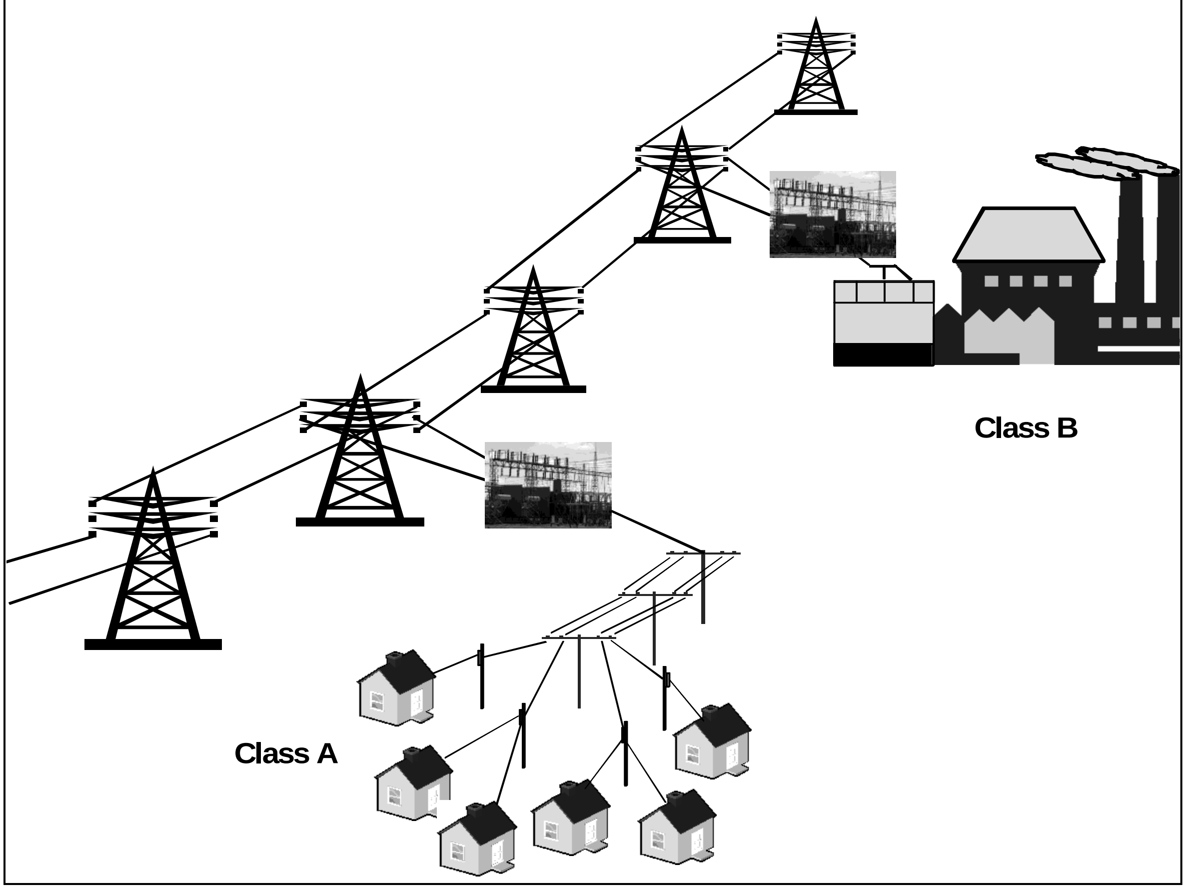
Q WHY WOULD CLASSIFYING ALL DISTRIBUTION NETWORK COSTS TO DEMAND NOT BE CONSISTENT WITH COST CAUSATION?

A Although the distribution network is sized to meet expected peak demand, it must also provide direct connection to the customer while providing the necessary voltage support to allow power to flow to the customer. Absent a distribution network and the voltage support it provides, electricity cannot flow to customers. Thus, this investment is essential and unrelated to the amount of power and energy consumed by customers, which is why classifying these costs entirely to demand is not consistent with cost causation.

C31-3116

If DEF were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of distribution lines because they are required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced. Consider the diagram below, which shows the distribution network for a utility with two customer classes, A and B.

Illustration Showing the Customer Component of Distribution Primary and Secondary Plant



C31-3117

C31-3118

The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

Q IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE ELECTRIC DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A Yes. For example, the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[26]

Q IS CLASSIFYING ALL DISTRIBUTION NETWORK COSTS TO DEMAND A CONSISTENT PRACTICE WITHIN THE DUKE ENERGY SYSTEM?

A No. DEF affiliates, DEC and DEP, classify a significant portion of distribution network costs as customer-related. The customer-related cost classifications are summarized in Tables 3 and 4.

[26] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, at 90 (Jan. 1992).

Table 3 Customer-Related Portion of Secondary Distribution Network Costs				
FERC Account	**DEC NC**	**DEP NC**	**DEC SC**	**DEP SC**
364: Poles, Towers & Fixtures	14%	19%	15%	21%
365: Overhead Conductors	43%	32%	41%	41%
366: Underground Conduit	80%	73%	72%	54%
367: Underground Conductors	44%	73%	41%	54%
368: Line Transformers	100%	0%	60%	0%
Sources: Docket No. E-7, Sub 1276, Docket No. E-2, Sub 1300, DEP Docket No. 2022-254-E, DEP Docket No. 2023-388-E				

Table 4 Customer-Related Portion of Primary Distribution Network Costs				
FERC Account	**DEC NC**	**DEP NC**	**DEC SC**	**DEP SC**
364: Poles, Towers & Fixtures	49%	62%	51%	60%
365: Overhead Conductors	46%	39%	54%	43%
366: Underground Conduit	78%	70%	69%	50%
367: Underground Conductors	42%	70%	32%	50%
368: Line Transformers	0%	0%	0%	0%
Sources: Docket No. E-7, Sub 1276, Docket No. E-2, Sub 1300, DEP Docket No. 2022-254-E, DEP Docket No. 2023-388-E				

As Tables 3 and 4 demonstrate, DEF's affiliates recognize that a significant portion of distribution network costs are customer-related.

Q DOES ANY OTHER FLORIDA UTILITY RECOGNIZE A CUSTOMER-RELATED COMPONENT OF DISTRIBUTION NETWORK COSTS?

A Yes. In its 2021 rate case, TECO agreed to implement a customer-related portion of the distribution network. TECO is proposing to continue this practice in its pending 2024 rate case.[27]

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[27] *In re: Petition for Rate Increase by Tampa Electric Company,* Docket No. 20240026-EI, Prepared Direct Testimony and Exhibit of Jordan Williams at 14.

Q HAS DEF CONDUCTED A STUDY IDENTIFYING THE CUSTOMER-RELATED PORTION OF ITS DISTRIBUTION NETWORK COSTS?

A Yes. DEF conducted a MDS study and identified the customer-related costs for FERC Account Nos. 364, 365, 366, 367, and 368 as shown in Table 5.

Table 5
Customer-Related Costs from
DEF's Minimum Distribution System Study

FERC Account	Percentage
364: Poles, Towers & Fixtures	65%
365: Overhead Conductors	56%
366: Underground Conduit	52%
367: Underground Conductors	55%
368: Line Transformers	68%

Source: DEF Response to FIPUG ROG 2-36.

Q WHAT DO YOU RECOMMEND?

A DEF's CCOSS should be revised to recognize a customer-related component of distribution network costs consistent with the classifications shown in Table 5.

Recognizing a customer-related cost more fairly allocates distribution costs between rate classes. It also recognizes that there are additional customer-related costs to provide distribution service (other than the meter and service drop), and it allocates these costs based on the number of customers. Thus, it is consistent with cost causation, is an accepted industry practice, and this Commission previously approved its use for TECO.

Demand and Energy Loss Factors

Q DO YOU HAVE ANY CONCERNS WITH THE LOSS FACTORS USED BY DEF IN ITS CLASS COST-OF-SERVICE STUDY?

A Yes. There appears to be two fundamental problems.

First, losses are a function of electrical current, and current is highest during peak periods. Accordingly, the (peak) demand losses *should* be higher than the corresponding energy losses. Despite the physics behind the variable losses incurred by electric utilities, the energy loss factors used by DEF in this proceeding (which measure the average losses incurred over all 8,760 hours) are the same as the corresponding peak demand loss factors for all delivery voltages. This is demonstrated in Table 6.

Table 6
Duke Energy Florida
Delivery Efficiency Factors

Voltage	Demand	Energy
Secondary	0.957172	0.957172
Primary	0.975237	0.975237
Transmission	0.985237	0.985237

Source: MFR Schedule E-10.

A delivery efficiency factor is the inverse of a loss factor. The higher the delivery efficiency factor, the lower the loss factor, and vice versa.

Second, DEF derived the loss factors for primary distribution voltage by subtracting 1% from the corresponding transmission loss factors. All of the remaining losses were attributed to secondary distribution voltage. Thus, DEF did not conduct an actual distribution loss study. Had DEF conducted a distribution loss study, it is possible that the loss factors for both primary and secondary distribution voltages would be higher.

Q WHAT IS THE BASIS FOR YOUR ASSERTION THAT A DISTRIBUTION LOSS STUDY WOULD HAVE REVEALED HIGHER LOSS FACTORS TO PROVIDE SERVICE AT PRIMARY AND SECONDARY DISTRIBUTION VOLTAGES?

A In its pending rate case, TECO conducted a distribution loss study. The results of TECO's loss analysis are summarized in Table 7.

Table 7
Tampa Electric Company
Delivery Efficiency Factors

Voltage	Demand	Energy
Secondary	0.935585	0.947848
Primary	0.962361	0.975070
Transmission	0.980071	0.986991

Source: Docket No. 20240026-EI, MFR Schedules E-11 and E-19b.

As Table 7 demonstrates, TECO's demand losses are higher than the corresponding energy losses. Further, the losses for primary and secondary distribution voltages appropriately reflect the higher losses incurred to deliver electricity to customers taking service at these voltages.

Q WHAT DO YOU RECOMMEND?

A DEF's peak demand and energy and loss factors are clearly understated for primary and secondary distribution voltages. Accordingly, I recommend replacing DEF's loss factors with the demand and energy loss factors by delivery voltage that TECO is using in its pending rate case, as shown in Table 7.

The Commission should order DEF to conduct a full-scale distribution loss study for its next rate case. Preferably that study should be reviewed by all parties prior to the filing of DEF's next rate case.

C31-3122

<u>Revised CCOSS</u>

Q HAVE YOU QUANTIFIED THE IMPACT OF USING 4CP RATHER THAN 12CP TO ALLOCATE PRODUCTION AND TRANSMISSION DEMAND-RELATED COSTS?

A Yes. **Exhibit JP-3** shows the derivation of the 4CP demand allocation factors. **Exhibit JP-4** is a revised CCOSS using 4CP (instead of 12CP+25% AD) for production and 4CP (instead of 12CP) for transmission. In addition, PTCs were allocated on an energy basis. As discussed earlier, PTCs are earned for every MWh generated from DEF's owned solar projects. Thus, allocating PTCs on an energy basis would better reflect cost causation than DEF's proposal, which spreads PTCs on plant in service.

C31-3123

4. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

Q HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES DEF SERVES?

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism.

Q WHAT IS THE PRINCIPLE OF GRADUALISM?

A Gradualism is a concept that is applied to avoid rate shock; that is, no class should receive an overly-large or abrupt rate increase. Thus, rates should move gradually to cost, rather than all at once, because moving rates immediately to cost would result in rate shock to the affected customers.

Q SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?

A Yes. Cost-based rates are fair because each class's rates reflect its cost to serve, no more and no less; they are efficient because, when coupled with a cost-based rate design, customers are provided with the proper incentive to minimize their costs, which

C31-3124

will, in turn, minimize the costs to the utility; they enhance revenue stability because changes in revenues due to changes in sales will translate into offsetting changes in costs; and they encourage conservation because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions.

Q DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal.

Q SHOULD GRADUALISM BE MEASURED RELATIVE TO BASE REVENUES OR TOTAL REVENUE?

A Gradualism should be measured on base revenues. This is because only base revenues are subject to change in this proceeding. Total revenues include base revenues as well as the revenues collected under DEF's five separate cost recovery mechanisms:

- Fuel;
- Energy Efficiency;
- Capital Cost Recovery;
- Storm Protection; and
- Storm Cost.

None of these cost recovery mechanisms are subject to change in a base rate case. Further, gradualism is not considered in any of the cost-recovery mechanism. A general rate case is the only venue in which gradualism can be properly applied.

C31-3125

C31-3126

Thus, measuring the impact of those proposed increases on ***base*** revenues is the only proper way to determine whether DEF's proposed class revenue allocation results in rate shock.

Q ARE THE PROPOSED BASE RATE INCREASES IN THIS PROCEEDING THE ONLY INCREASES THAT CUSTOMERS WOULD EXPERIENCE?

A No. In its pending conservation goals proceeding, DEF is proposing to reduce the Demand Credits applicable to Curtailable Service (CS) and Interruptible Service (IS) by 25% and 40%, respectively.

Q DOES DEF INCLUDE THE IMPACT OF REDUCING THE CURTAILABLE AND INTERRUPTIBLE SERVICE DEMAND CREDITS IN THIS PROCEEDING?

A No.

Q HOW WOULD THE 25% AND 40% REDUCTIONS IN THE CURTAILABLE AND INTERRUPTIBLE SERVICE DEMAND CREDITS IMPACT BASE RATES CHARGED TO THESE CUSTOMERS?

A The proposed reductions would generate additional revenue of $21.1 million from CS and IS customers.[28] These increases were ignored by DEF in determining the base revenue increases by customer class. Specifically, DEF is proposing base revenue increases of $22.9 million (30%) for CS and IS customers in 2025. Thus, if the CS and IS credits are reduced as DEF is proposing, and DEF receives its requested 2025 base revenue increase, CS and IS customers would experience base revenue

[28] MFR Schedule E-13c; MFR Schedule E-14; Rate Schedule CS-2 and Rate Schedule IS-2. See also, *In Re: Commission Review of Numeric Conservation Goals (Duke Energy Florida, LLC)*, Docket No. 20240013-EG, Direct Testimony of Tim Duff at 22 (Apr. 2, 2024).

increases of 213%. Not only would the combined rate increases violate the principle of gradualism, they would have a deleterious impact on the cost competitiveness and sustainability of the affected customers.

Q HAVE YOU DEVELOPED AN RECOMMENDED CLASS REVENUE ALLOCATION BASED ON YOUR REVISED CLASS COST-OF-SERVICE STUDIES?

A Yes. **Exhibit JP-5** uses FIPUG's 4CP/MDS CCOSS with the revised loss factors and PTC/ITC allocations, as discussed previously. My recommendation would result in moving a majority of rate classes to a relative rate of return of 1.01, which is just slightly above parity. Consistent with gradualism, the LS Energy class would receive no increase because it is already providing a rate of return that exceeds DEF's proposed system average rate of return, and no class would receive a base revenue increase higher than 1.5 times the 19.3% system average base revenue increase. For purposes of this illustration, I have assumed no change in either the CS or IS Demand Credits. Should the CS and IS Demand Credits be reduced, the impact should be recognized in limiting the combined revenue increases to not more than 1.5 times the system average base revenue increase.

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5. RATE DESIGN

Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I address DEF's proposed TOU rating periods.

Q HOW SHOULD RATES BE DESIGNED?

A Rate design is an extension of the cost allocation process. Also referred to as "intraclass" allocation, rate design determines how the costs allocated to each customer class are recovered from the customers within the class. Thus, rates should be designed consistent with the methodologies used to allocate costs in the CCOSS.

Further, the purpose of rate design is to establish charges that reflect cost while also sending proper price signals to encourage customers to respond in an appropriate manner. A rate design that fails to either provide proper price signals or meaningful opportunities for customers to respond to price signals is not only not cost-based, it will also discourage customer engagement. The proposed TOU rating periods and price signals in DEF's TOU rate schedule achieve neither objective.

Q WHAT CHANGES IS DEF PROPOSING TO THE TIME-OF-USE RATING PERIODS?

A DEF is proposing only minor changes in the TOU rating periods. The current and proposed TOU rating periods are summarized in Table 8 on the following page.

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<table>
<tr><th colspan="3">Table 8
Time of Use Periods</th></tr>
<tr><th>Period</th><th>Present</th><th>Proposed</th></tr>
<tr><td>On-Peak (Year-round)*</td><td colspan="2">6 p.m. to 9 p.m.</td></tr>
<tr><td>On-Peak (Winter)*</td><td colspan="2">5 a.m. to 10 a.m.</td></tr>
<tr><td>Discount (Non-Winter)</td><td colspan="2">12 a.m. to 6 a.m.</td></tr>
<tr><td>Discount (Winter)</td><td>N/A</td><td>12 a.m. to 3 a.m.</td></tr>
<tr><td>Winter Months</td><td colspan="2">Dec. Jan. Feb.</td></tr>
<tr><td colspan="3">* Weekdays excluding holidays.
Source: Direct Testimony of Matthew Chatelain at 11-12</td></tr>
</table>

As Table 8 shows, only slight revisions are being made to the TOU periods. Other than renaming the Super Off-Peak period to “Discount” period, DEF is proposing to add a second discount period in the winter months to encourage EV charging.

Q WHY DO YOU BELIEVE THAT DEF’S TIME-OF-USE RATING PERIODS ARE NOT COST-BASED?

A As discussed in further detail subsequently, DEF’s TOU rating periods were developed using a Cost Duration Method (CDM) that allocates the vast majority of production and transmission plant-related costs to hours other than DEF’s peak period demands. The impact of this costing philosophy is evident in the proposed Mid-Peak Demand charges in DEF’s IST-2 rate schedule. Table 9 on the following page summarizes the proposed IST-2 Demand charges.

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Table 9 Interruptible Service – Transmission < 230 kV			
Charge	**Proposed Rate**	**Mar – Nov.**	**Dec. – Feb.**
On-Peak	$2.75	6 p.m.–9 p.m.	5 a.m.-10 a.m. 6 p.m.–9 p.m.
Mid-Peak	$5.28	6 a.m.–12 a.m.	3 a.m.–12 a.m.
Base Demand	$1.86	All Hours	All Hours
Discount Hours	$1.86	12 a.m.–6 a.m.	12 a.m. –3 a.m.

Source: Rate Schedule IST-2.

As Table 9 demonstrates, the Mid-Peak Demand charges would account for the vast majority of the total Demand charges recovered under Schedule IST-2. Even if a manufacturing customer were to completely avoid On-Peak hours, the Demand charges would not be significantly reduced. This is because the Mid-Peak Demand charges would apply during both On- and Off-Peak hours. Further, because they are too narrowly defined, there would be little opportunity for manufacturing customers to shift load to the lower cost Discount period. This is demonstrated in Table 10.

Table 10 Number of Hours in DEF's Proposed Schedule IST-2 TOU Rating Periods			
Period	**Mar – Nov.**	**Dec. – Feb.**	**Total**
On-Peak	573	512	1,085
Off-Peak	4,359	1,399	5,758
Discount	1,644	273	1,917

As Table 10 demonstrates, DEF's proposed Schedule IST-2 is not a legitimate TOU rate because the prices are essentially unchanged for the vast majority of the hours in a typical year. This is because the Discount period (which is the only period that the proposed On-Peak and Mid-Peak Demand charges would not apply in Schedule IST-2) constitutes only 1,917 (22%) of the hours in a typical year. Further, the proposed On-Peak Demand charge is small relative to the proposed Mid-Peak Demand charges. Thus, DEC's TOU rating periods fail because they would send the same price signal during the vast majority (78%) of the hours.

Q WHAT IS THE JUSTIFICATION FOR THE TIME-OF-USE RATING PERIODS AND PRICING DIFFERENTIALS?

A DEF witness, Matthew Chatelain, states that the TOU rating periods and pricing are supported by the CDM.[29]

Q PLEASE EXPLAIN THE COST DURATION METHOD.

A The CDM was used to define how production and transmission plant-related costs and marginal energy costs vary by time-of-use. As discussed in Mr. Chatelain testimony, plant related costs are allocated to time periods during which system assets are used, regardless of the circumstances. Specifically, the costs for assets used during all hours are allocated to all hours, while the costs for assets used during peaking hours are more concentrated in those hours.[30]

[29] Direct Testimony of Matthew Chatelain at 13.

[30] *Id.*

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Q HOW WAS THE COST DURATION MODEL USED TO DETERMINE THE TIME BEARING NATURE OF PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS?

A Production plant-related costs were spread to *all* hours based on net peak load, which is the difference between the total (*i.e.,* gross) load served and the amount of utility scale solar generation. Transmission plant-related costs were spread to *all* hours based on gross load. As the hourly load increases, the CDM allocates a proportionally larger share of plant-related costs to that hour. Because it spreads costs to all hours, regardless of the circumstances, the CDM clearly understates the costs assigned to on-peak hours. Only [redacted]% of production and transmission plant-related costs were allocated to the hours in which the net and gross system loads, respectively, are projected to be 90% or higher of the annual system peak. This result clearly demonstrates that the CDM essentially apportions costs to each hour based on the relative load in each hour, rather than the extent in which the load in a particular hour impacts system reliability or causes DEF to incur high energy costs. Accordingly, CDM is a usage-based, rather than a cost-based, model.

Q IS IT REASONABLE TO SPREAD PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS TO ALL 8,760 HOURS IN A TYPICAL YEAR?

A No. The CDM ignores cost causation because the amount of production and transmission facilities must be capable of serving the expected system peak demands, while providing an ample cushion to ensure that DEF can serve its firm loads *at all times*. Spreading these costs to all hours based on usage, rather than to peak periods, is also fundamentally inconsistent with DEC's CCOSS, which has historically allocated costs, in significant part, based on each customer class's coincident peak demand.

Further, DEF has provided no evidence that production and transmission plant-related costs are caused by loads in all 8,760 hours of the year. In fact, this assumption is demonstrably untrue for production plant, as previously discussed.

Q WHAT DO YOU RECOMMEND?

A The current TOU rating periods and pricing differentials should be retained. Further, the Commission should order DEF to develop a new TOU rate design in collaboration with the Commission Staff and other interested parties.

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6. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?

A The Commission should make the following findings:

- Reject the 2026 and 2027 test years.
- Adopt a lower ROE that reflects DEF's reduced regulatory lag and financial risk.
- Adopt the 4CP method of allocating production and transmission plant.
- Adopt a Minimum Distribution System analysis in allocating distribution network costs.
- Reject DEF's allocations of production tax credits and investment tax credits.
- Adopt FIPUG's recommendation to allocate production tax credits on an energy basis and investment tax credits on production plant.
- Reject DEF's loss factors.
- Adopt FIPUG's recommended demand and energy loss factors by delivery voltage.
- Require DEF to conduct a full-scale distribution loss study in its next rate case.
- Require DEF to completely revise the TOU rating periods and pricing.

Q DOES THAT CONCLUDE YOUR TESTIMONY?

A Yes.

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APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 14323 South Outer 40, Suite 206N, Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing

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requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

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APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Cross-Rebuttal	TX	Distribution Load Dispatch Expense; Residential Class MDD; LCUST Allocation Factor; Call Center Cost Allocation; Wholesale Distribution Service for Battery Energy Storage System	6/7/2024
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	20240026-EI	Direct	FL	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/6/2024
DOMINION ENERGY SOUTH CAROLINA, INC.	South Carolina Utility Energy Users Committee	2024-34-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/5/2024
DUKE ENERGY FLORIDA, LLC	Florida Industrial Power Users Group	20240013-EG	Direct	FL	Curtailable General Service; Interruptible General Service	6/5/2024
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Direct	TX	Transmission Operation and Maintenance Expense; Property Insurance Reserve; Class Cost-of-Service Study; Rate Design; Tariff Changes	5/16/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Cross-Rebuttal	TX	Turk Remand Refund	5/10/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Surrebuttal	SC	Class Cost-of-Service Study; Revenue Allocation and Rate Design	4/29/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Direct	TX	Turk Remand Refund	4/17/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/8/2024
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	55378	Direct	GA	Deferred Accounting; Additional Sum; Specific Capacity Additions; Distributed Energy Resource and Demand Response Tariffs	2/15/2024
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022

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MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advance Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020

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APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019

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APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019

To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: **J. Pollock Testimony filed from 1976 through the prior year**

APPENDIX C

Procedures and Key Principles of a CCOSS

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kWs). This includes production, transmission, and some distribution investment and related fixed O&M expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWhs). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

C31-3146

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes several key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (i.e., demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities. Finally, customers who self-serve all or a portion of their power needs from BTMG will have dramatically different load characteristics than customers who purchase all or most of the power from the utility. Thus, they should be costed separately.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- Operate at higher load factors;
- Take service at higher delivery voltages; and
- Use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

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In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than either primary distribution or primary substation customers. More investment is required to serve a primary distribution than a primary substation customer. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis. Efficiency can be measured in terms of load factor. Load factor is the ratio of Average Demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

C31-3149

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	**DOCKET NO. 20240025-EI** **Filed: June 11, 2024**

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 14323 S. Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20240025-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 11th day of June 2024.

KITTY TURNER
Notary Public, Notary Seal
State of Missouri
Lincoln County
Commission # 15390610
My Commission Expires 04-25-2027

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2027.

(Whereupon, prefiled direct testimony of Steve W. Chriss was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY DUKE ENERGY FLORIDA, LLC	))	**DOCKET NO. 20240025-EI**

DIRECT TESTIMONY AND EXHIBITS OF

STEVE W. CHRISS

ON BEHALF OF

FLORIDA RETAIL FEDERATION

JUNE 11, 2024

Contents

Exhibits

Exhibit SWC-1: Witness Qualifications Statement

Exhibit SWC-2: Impact of DEF's Proposed Increase in Return on Equity ($000) vs. Originally Approved, PTY 2025

Exhibit SWC-3: Impact of DEF's Proposed Increase in Return on Equity ($000) vs. Originally Approved, PTY 2026

Exhibit SWC-4: Impact of DEF's Proposed Increase in Return on Equity ($000) vs. Originally Approved, PTY 2027

Exhibit SWC-5: Impact of DEF's Proposed Increase in Return on Equity ($000) vs. ROE Trigger, PTY 2025

Exhibit SWC-6: Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2021 to Present

Introduction

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

A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville, AR 72716-0550. I am employed by Walmart Inc. ("Walmart") as Senior Director, Utility Partnerships.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Florida Retail Federation ("FRF"), a statewide trade association of more than 8,000 of Florida's retailers, many of whom are retail customers of Duke Energy Florida, LLC ("DEF" or "Company"). As an example, Walmart has 93 stores and clubs, one distribution center, and related facilities that take service from DEF.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to

Director, Energy and Strategy Analysis in October 2016 and the position was re-titled in October 2018. I was promoted to my current position in July 2023. My Witness Qualifications Statement is attached as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I testified in Docket Nos. 20110138-EI, 20120015-EI, 20130140-EI, 20130040-EI, 20140002-EI, 20160021-EI, 20160186-EI, 20190061-EI, 20200067-EI, 20200069-EI, 20200070-EI, 20200071, 20200092, 20200176, 20210015, 20240012-EG, 20240013-EG, 20240014-EG, 20240015-EG, 20240016-EG, 20240017-EG, and 20240026-EI.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 270 proceedings before 42 other utility regulatory commissions. I have also submitted testimony before legislative committees in six states. My testimony has addressed topics including, but not limited to, cost of service and rate design, return on equity, revenue requirements, ratemaking policy, net metering, community solar, large customer renewable programs, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

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Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. GENERALLY, WHY ARE UTILITY CUSTOMERS, INCLUDING RETAILERS AND OTHER COMMERCIAL CUSTOMERS, CONCERNED ABOUT DUKE ENERGY FLORIDA'S (DEF) PROPOSED RATE INCREASE?

A. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate, which impacts retailers' customers and employees. Rate increases also directly impact retailers' customers, who are DEF's residential and small business customers. Given current economic conditions, a rate increase is a serious concern for retailers and their customers, and the Commission should consider these impacts thoroughly and carefully in ensuring that any increase in DEF's rates is only the minimum amount necessary for the utility to provide adequate and reliable service.

Purpose of Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to DEF's rate case filing and to provide recommendations to assist the Commission in its thorough and careful consideration of the customer impact of the Company's proposed rate increases.

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Q. PLEASE SUMMARIZE FRF'S RECOMMENDATIONS TO THE COMMISSION.

A. FRF's recommendations to the Commission are as follows:

1) The Commission should thoroughly and carefully consider the impact on customers in examining the requested ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates reflects the minimum amount necessary to compensate the Company for adequate and reliable service, while also providing DEF an opportunity to earn a reasonable return for its shareholders. Specifically, the Commission should closely examine DEF's proposed revenue requirement increase and the associated ROE in light of:

   a. The customer impact of the resulting revenue requirement increases;
   b. The use of a future test year, which reduces regulatory lag by allowing the utility to include projected costs in its rates at the time they will be in effect;
   c. The high degree of revenue certainty realized by DEF through recovery of a substantial proportion of total retail revenues through cost recovery clauses;
   d. Recent rate case ROEs approved by the Commission; and
   e. Recent rate case ROEs approved by other state regulatory commissions nationwide.

2) For the purposes of this docket, at this time FRF does not take a position on the proposed cost of service study.

3) For the purposes of this docket, FRF does not oppose the Company's proposed

revenue allocation methodology.

4) FRF supports the Company's proposed expansion of the Clean Energy Connection ("CEC") program.

5) FRF does not oppose Commission approval of the proposed Make Ready Credit ("MRC") program.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE FRF'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

Return on Equity

Q. WHAT IS YOUR UNDERSTANDING OF DEF'S PROPOSED REVENUE REQUIREMENT INCREASE IN THIS DOCKET?

A. My understanding is that DEF is requesting a general base rate increase for the 2025 test year of $593 million to be effective January 1, 2025, and additional subsequent year adjustments of $98 million to be effective January 1, 2026 and $129 million to be effective January 1, 2027. See Direct Testimony of Melissa Seixas, page 21, line 2 to line 7. In total, DEF is requesting a cumulative increase in its base rates over three years of $820 million per year. In total, DEF is asking its customers to pay more than $2.1 billion in additional base rate revenues over the 2025-2027 period.

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?

A. The Company proposes an ROE of 11.15 percent, based on a range of 10.4 percent to 11.4 percent, or 10.5 percent to 11.5 percent, adjusting for the impact of common equity flotation costs. See Direct Testimony of Adrien McKenzie, page 3, line 12 to line 20.

Q. IS DEF'S PROPOSED ROE HIGHER THAN THEIR LAST APPROVED MIDPOINT ROE?

A. Yes. The Company's proposed ROE represents an increase of 130 basis points from DEF's last approved midpoint ROE of 9.85 percent.[1] The proposed ROE is also 105 basis points higher than the ROE trigger result of 10.1 percent approved in 2022.[2]

Q. IS FRF CONCERNED ABOUT THE REASONABLENESS OF THE COMPANY'S PROPOSED ROE?

A. Yes, especially when viewed in light of:

1) The customer impact of the resulting revenue requirement increases;
2) The use of a future test year, which reduces regulatory lag by allowing the utility to include projected costs in its rates at the time they will be in effect;
3) The high degree of revenue certainty that DEF realizes through the use of pass-through type cost recover clauses;

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[1] *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC*, Docket No. 20210016-EI, Order No. PSC-2021-0202-AS-EI, Final Order Approving 2021 Settlement Agreement (issued June 4, 2021).
[2] *In re: Petition for limited proceeding to implement return on equity trigger provision of 2021 settlement agreement, by Duke Energy Florida, LLC*, Docket No. 20220143-EI, Order No. PSC-2022-0357-FOF-EI, Order Implementing Duke Energy Florida, LLC's Return on Equity Trigger (issued October 21, 2022).

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4) Recent rate case ROEs approved by the Commission; and

5) Recent rate case ROEs approved by other state regulatory commissions nationwide.

Q. WHAT IS YOUR CONCERN WITH DEF'S ROE RELATIVE TO ITS USE OF COST RECOVERY CLAUSES?

A. Through the use of cost recovery clauses and charges, such as the Fuel and Purchased Power Cost Recovery Clause, the Environmental Cost Recovery Clause, the Energy Conservation Cost Recovery Clause, and other such clauses, DEF realizes great revenue certainty. For example, DEF's March 2024 Earnings Surveillance Report shows that DEF recovered approximately 61 percent of its total retail operating revenues through cost recovery clauses. This great degree of revenue certainty demonstrates correspondingly great reductions in risk, which should be reflected in the ROE approved for the Company.

Customer Impact

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT FOR THE 2025 TEST YEAR OF DEF'S PROPOSED INCREASE IN ROE FROM THE COMPANY'S LAST APPROVED MIDPOINT ROE OF 9.85 PERCENT?

A. The proposed increase in ROE from DEF's last approved midpoint ROE has an annual revenue requirement impact on the Company's rates of approximately $163.5 million for 2025. This constitutes about 27.6 percent of the Company's overall increase request for the 2025 test year. *See* Exhibit SWC-2. For the 2026 test year, the increase has a revenue requirement impact of approximately $171.2

million, or 28.8 percent of the Company's request for the 2026 test year. *See* Exhibit SWC-3. Finally, for the 2027 test year, the increase has a revenue requirement impact of approximately $177.8 million, or 30 percent of the Company's request for the 2027 test year. *See* Exhibit SWC-4.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT FOR THE 2025 TEST YEAR OF DEF'S PROPOSED INCREASE IN ROE FROM THE COMPANY'S ROE TRIGGER MIDPOINT ROE OF 10.1 PERCENT?

A. When the approved ROE trigger midpoint is considered, the annual revenue requirement impact on DEF's rates is approximately $132.1 million for 2025. This constitutes about 22.3 percent of the Company's overall increase request for the 2025 test year. *See* Exhibit SWC-5.

Future Test Year

Q. HAS THE COMMISSION RECOGNIZED THAT THE USE OF A FUTURE TEST YEAR IMPACTS THE UTILITY'S EXPOSURE TO REGULATORY LAG?

A. Yes. The use of a projected test year reduces the utility's financial risk due to regulatory lag because, as the Commission has previously stated, "the main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect."[3] As such,

[3] *In re: Request for rate increase by Gulf Power Company*, Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI, Order Granting in Part and Denying in Part Gulf Power Company's Petition for Rate Increase (issued June 10, 2002), page 9.

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the Commission should carefully consider the level of ROE required in light of the Company's reduced exposure to regulatory lag.

Recent ROEs Approved by the Commission

Q. IS DEF'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN ROEs RECENTLY APPROVED BY THE COMMISSION?

A. Yes. In 2021, in addition to the DEF ROE discussed above, the Commission approved Tampa Electric Company's 2021 Settlement Agreement for its base rate case in Docket 20210034-EI, which included approval of an ROE midpoint of 9.95 percent.[4] Additionally, the Commission approved Florida Power & Light Company's 2021 Settlement Agreement of its base rate case in Docket 20210015-EI, which included approval of an ROE midpoint of 10.6 percent.[5]

As such, the Company's proposed 11.15 percent ROE midpoint is excessive as compared to recent Commission actions regarding ROE.

[4] *In re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 20210034-EI, Order No. PSC-2021-0423-S-EI, Final Order Approving Stipulation and Settlement Agreement Between Tampa Electric Company and All Intervenors (issued June 4, 2021).
[5] *In re: Petition for rate increase by Florida Power & Light Company*, Docket No. 20210015-EI, Order No. PSC-2021-0446-S-EI Approving 2021 Stipulation and Settlement Agreement (issued December 2, 2021).

ROEs Approved for Other Duke Energy Operating Companies

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROEs RECENTLY APPROVED FOR OTHER DUKE OPERATING COMPANIES?

A. Yes. Since 2021 the following ROEs have been authorized for other Duke Energy operating companies.

- Duke Energy Carolinas was authorized an ROE of 9.6 percent in their North Carolina rate case that concluded in 2021 (Docket E-7, Sub 1214). Duke Energy Carolinas was subsequently authorized an ROE of 10.1 percent in their North Carolina rate case that concluded in 2023 (Docket E-7, Sub 1300).
- Duke Energy Progress was authorized an ROE of 9.6 percent in their North Carolina rate case that concluded in 2021 (Docket E-2, Sub 1219). Duke Energy Progress was subsequently authorized an ROE of 9.8 percent in their North Carolina rate case that concluded in 2023 (Docket E-2, Sub 1300).
- Duke Energy Ohio was authorized an ROE of 9.5 percent in their Ohio rate case that concluded in 2022 (Docket 21-0887-EL-AIR).
- Duke Energy Progress was authorized an ROE of 9.6 percent in their South Carolina rate case that concluded in 2022 (Docket 2022-254-E).
- Duke Energy Kentucky was authorized an ROE of 9.75 percent in their Kentucky rate case that concluded in 2023 (Docket 2022-00372).

As such, the Company's proposed 11.15 percent ROE midpoint is excessive as compared to recent ROEs authorized for the other Duke Energy operating companies.

National Utility Industry ROE Trends

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROEs APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS IN 2021, 2022, 2023, AND SO FAR IN 2024?

A. Yes. According to data from S&P Global Market Intelligence ("S&P Global"), a financial news and reporting company, the average of the 118 reported electric utility rate case ROEs authorized by regulatory commissions for investor-owned utilities in 2021, 2022, 2023, and so far in 2024, is 9.50 percent. The range of reported authorized ROEs for the period is 7.36 percent to 11.45 percent, and the median authorized ROE is 9.50 percent. The average and median values are significantly below the Company's proposed ROE of 11.15 percent. As such, DEF's proposed 11.15 percent midpoint ROE is excessive when compared to broader electric industry trends. *See* Exhibit SWC-6.

Q. SEVERAL OF THE REPORTED AUTHORIZED ROEs ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR VERTICALLY INTEGRATED UTILITIES?

A. In the group reported by S&P Global, the average ROE for vertically integrated utilities authorized from 2021 through present is 9.62 percent. The average ROE authorized for vertically integrated utilities in 2021 was 9.54 percent; in 2022, it

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was 9.60 percent; in 2023, it was 9.71 percent; and thus far in 2024, it is 9.72 percent. *Id.* As such, the Company's proposed 11.15 percent ROE is excessive in light of broader electric industry trends and, in fact, as shown in Figure 1, would be the second highest approved ROE (out of 84) for a vertically integrated utility from 2021 to present, if approved by the Commission.

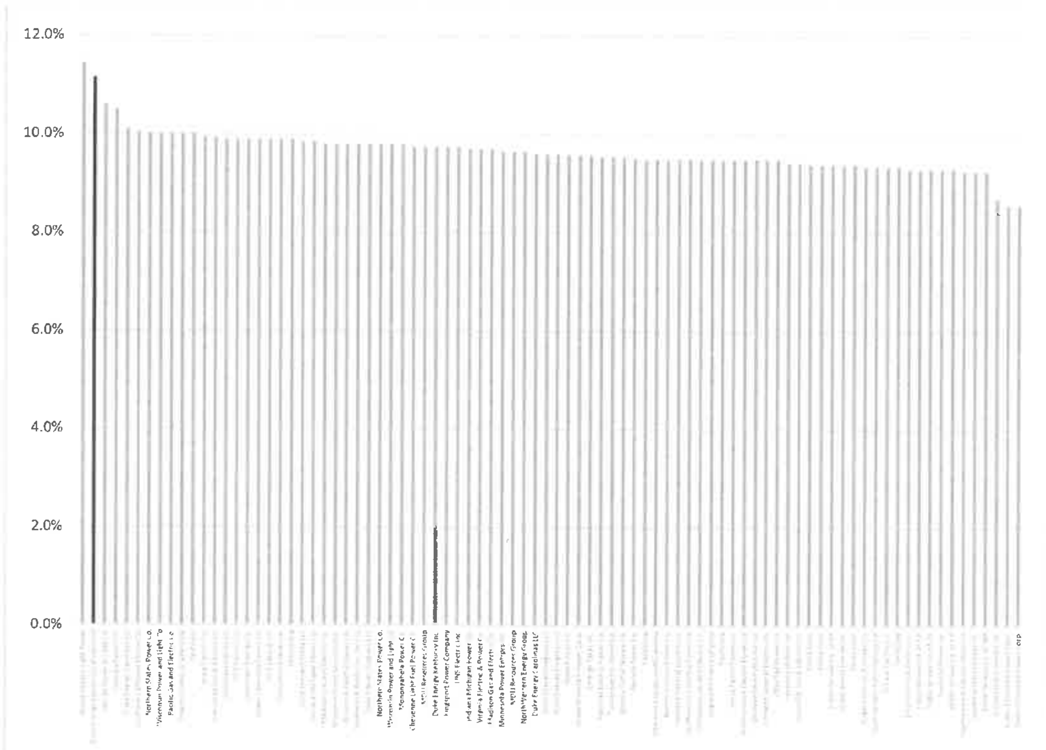

Figure 1. DEF's Proposed ROE Versus Authorized ROEs for Vertically Integrated Utilities, 2021 to present. Source: Exhibit SWC-6.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT WERE THE COMMISSION TO APPROVE AN ROE FOR DEF EQUIVALENT TO 9.72 PERCENT, THE AVERAGE AUTHORIZED ROE NATIONWIDE FOR VERTICALLY INTEGRATED UTILITIES IN 2024?

A. If the Commission were to approve an ROE for DEF of 9.72 percent, versus the Company's proposal of 11.15 percent, it would result in a reduction in the

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Company's proposed revenue requirement of $180.3 million, or 30.4 percent. *See* Exhibit SWC-7.

Q. IS FRF RECOMMENDING THAT THE COMMISSION BE BOUND BY ROEs AUTHORIZED BY OTHER STATE REGULATORY COMMISSIONS?

A. No. Decisions of other state regulatory commissions are not binding on the Commission. Additionally, each state regulatory commission considers the specific circumstances in each case in its determination of the proper ROE. FRF is providing this information to illustrate a national customer perspective on industry trends in authorized ROE.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN REGARD TO THE COMPANY'S PROPOSED ROE?

A. The Commission should thoroughly and carefully consider the impact on customers in examining the requested ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates reflects the minimum amount necessary to compensate the Company for adequate and reliable service, while also providing DEF an opportunity to earn a reasonable return for its shareholders.

Cost of Service and Revenue Allocation

Q. GENERALLY, WHAT IS FRF'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?

A. FRF advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, sends proper price signals, and minimizes price distortions.

Q. WHAT IS FRF'S UNDERSTANDING OF THE COMPANY'S PROPOSED COST OF SERVICE STUDY IN THIS DOCKET?

A. It is FRF's understanding that the Company's proposed cost of service study in this docket has been filed in accordance with the 2021 Settlement Agreement ("2021 Agreement") approved by the Commission in Order No. PSC-2021-0202A-AS-EI. Neither FRF nor Walmart were parties to the settlement, and it is important to note that the settlement was the result of negotiation between the parties with give and take across the breadth of issues, and signing is not necessarily an endorsement of any individual provision of a settlement. My understanding is that the 2021 Agreement states the Company will rely on the 12 CP and 25 percent AD methodology for production cost allocation, but no signing party waived their right to advocate for alternative production cost allocation methodologies in this docket. *See* 2021 Agreement, Appendix A, page 8.

Q. WHAT IS FRF'S POSITION ON THE COMPANY'S PROPOSED COST OF SERVICE STUDY?

A. For the purposes of this docket, at this time FRF does not take a position on the proposed cost of service study.

Q. HOW DOES THE COMPANY REPRESENT WHETHER RATES FOR A CUSTOMER CLASS ACCURATELY REFLECT THE UNDERLYING COST OF SERVICE?

A. The Company represents this relationship in its cost of service study results through a comparison of class-specific rates of return. *See* Schedule E-1. These rates of return can be converted into a rate of return index ("RRI"), which is an indexed measure of the relationship of the rate of return for an individual rate class to the total system rate of return. An RRI greater than 1.0 means that the rate class is paying rates in excess of the costs incurred to serve that class, and an RRI less than 1.0 means that the rate class is paying rates less than the costs incurred to serve that class. As such, those rate classes with an RRI greater than 1.0 shoulder some of the revenue responsibility for the classes with an RRI less than 1.0.

Q. HAS THE COMPANY CALCULATED A RRI FOR EACH CUSTOMER CLASS BASED ON DEF'S COST OF SERVICE RESULTS AT PRESENT RATES?

A. Yes, as shown in Table 1 below.

Table 1. Rate of Return Index, DEF Proposed Cost of Service Study Results, Present Rates.

Customer Class	Rate of Return (%)	RRI
RS	5.11	1.05
GS-1	7.00	1.44
GS-2	2.98	0.61
GSD, SS-1	4.21	0.87
CS, SS-3, IS, SS-2	2.63	0.54
LS – Energy	-1.30	(0.27)
LS – Facilities	4.53	0.93
EV Solution	12.08	2.49
Total Company		1.00

Sources: Schedule E-1, page 4.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S REVENUE ALLOCATION PROPOSAL?

A. My general understanding is that the Company proposes to limit the increase of each class to no more than 1.5 times the average system increase, and no class shall

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receive a decrease if there is an overall revenue requirement increase. *See* Direct Testimony of Marcia J. Olivier, page 42, line 1 to line 4. The resulting RRI per the Company's proposed revenue requirements and revenue allocation for 2025, 2026, and 2027 are shown in Table 2 below.

Table 2. Proposed Rate of Return Index, PTY 2025, PTY 2026, and PTY 2027.

Customer Class	RRI, PTY 2025	RRI, PTY 2026	RRI, PTY 2027
RS	1.01	1.01	1.01
GS-1	1.01	1.01	1.01
GS-2	0.93	0.94	0.97
GSD, SS-1	1.01	1.01	1.01
CS.SS-3, IS, SS-2	0.86	0.88	0.91
LS – Energy	0.62	0.63	0.64
LS – Facilities	1.00	1.00	1.00
EV Solution	1.00	1.00	1.00
Total Company	**1.00**	**1.00**	**1.00**

Sources: Schedule E-1, page 2 to page 4.

Q. WHAT IS FRF'S RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. For the purposes of this docket, FRF does not oppose the Company's proposed revenue allocation methodology.

Clean Energy Connection Program Expansion

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSAL TO EXPAND THE CEC PROGRAM?

A. My understanding is that the Company proposes to expand the CEC program to add five solar sites projected to go into service during the 2025, 2026, and 2027 test years. The total capacity of the five sites is approximately 375 MW. *See* Direct

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Testimony of Benjamin M. H. Borsch, page 19, line 17 to line 20.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED ALLOCATION OF PROGRAM CAPACITY?

A. My understanding is that the Company proposes to allocate eight percent of the expanded capacity to residential and small business customers, 64 percent to commercial and industrial customers, 18 percent to local governments, and 10 percent to higher education facilities. Within that allocation, the Company proposes to allocate 3.5 percent to low-income customers. *See* Direct Testimony of Marcia J. Olivier, page 21, line 15 to page 22, line 8.

Q. DOES THE COMPANY PROPOSE TO INTEGRATE THE ADDITIONAL CEC CAPACITY INTO THE EXISTING PROGRAM STRUCTURE?

A. Yes. *Id.*, page 22, line 18 to line 22.

Q. WHAT IS FRF'S RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. FRF supports the Company's proposed expansion of the CEC program as an avenue to support the achievement of renewable energy goals that its members may have.

Make Ready Credit Program

Q. WHAT IS YOUR GENERAL UNDERSTANDING OF THE COMPANY'S PROPOSED MAKE READY CREDIT (MRC) PROGRAM?

A. My understanding is the Company proposes the MRC program to provide an incentive, as a credit on a customer bill or a payment to a contractor, for the installation of the customer-side infrastructure required to service EV charging hardware. *See* Direct Testimony of Timothy J. Duff, page 12, line 9 to line 14.

Q. WHAT ARE THE COMPANY'S PROPOSED ELIGIBILITY REQUIREMENTS?

A. The Company proposes that residential and non-residential customers be eligible, as well as pre-approved homebuilders constructing homes served by DEF's distribution system. *Id.*, page 12, line 17 to line 22.

Q. WHAT PROCESS DOES THE COMPANY PROPOSE FOR NON-RESIDENTIAL CUSTOMER PARTICIPANTS?

A. The Company proposes that a participating customer file an application which includes invoices for the make ready infrastructure, a schematic diagram of the installation, a copy of the approved permit from the municipal or local permitting authority, and a completed customer usage form. The Company proposes that the application be submitted within 120 days following the later of the date on the most recent invoice included in the application or the date listed on the approved permit. *Id.*, page 15, line 21 to page 16, line 12.

Q. DOES THE COMPANY PRECLUDE CREDITING OF COSTS SUBJECT TO REIMBURSEMENT FROM THIRD-PARTY FUNDING SOURCES?

A. Yes. *Id.*, line 14 to line 16.

Q. DOES THE COMPANY PROPOSE CAPS TO THE MRC PROGRAM CREDITS?

A. Yes. The Company proposes to limit the per charger credit to the lesser of the four-year base revenue calculation from the new service or the customer's cost of

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installing make ready infrastructure. *Id.*, page 20, line 6 to line 9.

Q. WHAT IS FRF'S RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. FRF does not oppose Commission approval of the proposed MRC program.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of MacKenzie Marcelin was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	))))	DOCKET NO. 20240025-EI

TESTIMONY OF MACKENZIE D. MARCELIN

ON BEHALF OF

FLORIDA RISING AND LEAGUE OF UNITED LATIN AMERICAN CITIZENS

JUNE 11, 2024

Q. Please state your name and business address.

A. My name is MacKenzie Marcelin. My business address is 10800 Biscayne Blvd Suite 1050, Miami, FL 33161.

Q. What is your current position?

A. I am the Climate Justice Director at Florida Rising.

Q. What are your duties as Climate Justice Director?

A. In my role I am responsible for developing campaign strategies that address the climate crisis from a racial justice lens at the local, state, and federal levels. I am also tasked with designing and implementing actions and events to mobilize base, allies, and partners toward key climate justice policy wins. Lastly, I develop and activate natural disaster response and manage disaster response initiative work.

Q. Please summarize your qualifications and work experience.

A. In 2019, I was hired as a climate justice organizer at Florida Rising where I began my organizing work in climate justice. My general qualifications include organizing for 6 years and organizing multiple energy justice campaigns. I have experienced electricity disconnections and know the hardships they can cause. I have personally experienced energy insecurity, and as a Floridian, have had to engage in preparation for multiple hurricanes. I have a Bachelor of Arts in History from the University of Florida, with a focus on the Black experience, race, and inequality. My litigation experience is limited; however, I have participated in a few dockets at the Florida Public Service Commission.

Q. Have you ever testified before the Florida Public Service Commission before?

A. Yes, I have participated in a few dockets at the Florida Public Service Commission advocating on behalf of Florida Rising's values of racial and economic justice and for Florida Rising's members, who are mostly black and brown, and are facing high energy burdens due to high electric bill costs. In Docket Nos. 20190015-EG, 20190016-EG, 20190018-EG, 20190020-EG, 20190021-EG, *In re: Commission review of numeric conservation goals*, I gave testimony to the importance of energy efficiency in helping customers lower energy bills, especially for low-income communities and communities of color. For more information, please see a transcript of my remarks here: http://www.psc.state.fl.us/library/filings/2019/08186-2019/08186-2019.pdf. In Docket No. 20200219-EI, *In re: Petition to initiate emergency rulemaking to prevent electric utility shutoffs, by League of United Latin American Citizens, Zoraida Santana, and Jesse Moody*, I gave testimony to the importance of halting electric power disconnections for the health of members of low-income communities. For more information, please see a transcript of my remarks here: http://www.psc.state.fl.us/library/filings/2020/11330-2020/11330-2020.pdf. In Docket No. 202000181-EU, *In re: Proposed amendment of Rule 25-17.0021, F.A.C., Goals for Electric Utilities*, I gave testimony to the importance of energy efficiency in helping customers lower energy bills, especially for low-income communities and communities of color. For more information, please see a video of my remarks here: http://psc-fl.granicus.com/MediaPlayer.php?view_id=2&clip_id=3368 and here: http://psc-fl.granicus.com/MediaPlayer.php?view_id=2&clip_id=3335.

Q. Have you ever testified as a formal witness before the Florida Public Service Commission?

A. Yes, in the FPL Rate Case I submitted formal testimony on behalf of Florida Rising (Docket 20210015-EI). That testimony can be found here: https://www.floridapsc.com/pscfiles/library/filings/2021/06451-2021/06451-

2021.pdf. On June 5, 2024, I filed formal testimony in the energy-efficiency goal setting proceedings (Docket Nos. 20240012, 20240013, 20240014, 20240016, and 20240017). That testimony can be found here: https://www.floridapsc.com/pscfiles/library/filings/2024/04599-2024/04599-2024.pdf. On June 6, 2024, I filed formal testimony in the TECO rate case (Docket No. 20240026-EI). That testimony can be found here: https://www.floridapsc.com/pscfiles/library/filings/2024/04673-2024/04673-2024.pdf.

Q. On whose behalf are you testifying in this proceeding?

A. Florida Rising and the League of United Latin American Citizens of Florida (also known as "LULAC").

Q. What is Florida Rising?

A. We are a people-powered organization made up of members advancing economic and racial justice across Florida. We build independent political power that centers historically marginalized communities so everyday Floridians can shape the future. As an organization, we engaged in the 2019 FEECA Hearings, intervened in the 2021 FPL Rate Case, commented on the energy-efficiency rulemaking proceeding (Docket No. 20200181), including in the Rule hearing, commented in some of the fuel dockets and storm recovery dockets, and, in addition to this proceeding, have intervened in the Tampa Electric Company Rate Case and FEECA case, happening at the same time as this case.

Q. Does Florida Rising have members in Duke Energy Florida's service territory?

A. Yes, Florida Rising has members in Duke Energy Florida's ("Duke") service territory. We have at least 53 active members in Pinellas County and a number of

Duke members in the Orlando area, plus additional members scattered throughout the rest of Duke's territory. Also, Florida Rising as an organization pays electric bills to Duke for our office located in Duke's service territory.

Q. Why is Florida Rising in this proceeding?

A. As mentioned before, Florida Rising is an organization made up of members focused on empowering marginalized communities to advance racial and economic justice across Florida. In our climate justice work we want a future where the frontline and most impacted communities are at the center of energy policy, disaster response, and all climate change initiatives.

As I discuss below, Duke's residential customers, including Florida Rising's members, face some of the highest electricity bills in the nation. Our members face an affordability crisis between rising rents and rising electricity bills. While the Florida Public Service Commission does not regulate rental prices, it is supposed to regulate electricity prices.

Florida's dependency on fossil fuels has led to our current energy system polluting our communities, fueling our climate crisis, and leading many in dire economic straits. These issues in our energy system have an unequal and harmful impact on Black, Brown, and low-income communities. A 2020 report by ACEEE found that low-income, Black, Hispanic, and Native American households face higher energy burdens than the average household.[1] Rising housing costs, insurance costs, and stagnant wages have made Florida unaffordable, leaving families with high energy burdens. The financial hardship is forcing people to make tough choices between keeping the lights on or paying for groceries or prescription medications or living in hot and unsafe housing conditions. All the while, major utility companies have been experiencing record profits over the last few years.

Florida has been experiencing an uptick in climate disasters like extreme heat, sea level rise, flooding, and severe storms, which are leaving our neighborhoods and infrastructure vulnerable. Record high heat days,[2] stronger and more frequent storms,[3] and other climate disasters are a direct result of our energy system's reliance on dirty fossil fuels. The increase in extreme heat days means that more energy and access to A/C are a requirement in Florida for keeping our homes healthy, habitable, and cool. Stronger and more frequent storms threaten the reliability of our electrical grid, causing loss of property to our state and an increase in illness and death. The increase in extreme disasters places an unfair burden on communities' colors and often leads them into a more vulnerable state than before.

Finally, one of the many reasons Florida Rising is participating in this proceeding is we believe that Florida must transition to a clean energy system with more community members included in the decision-making. If we do that, we can ensure that everyone has access to clean, affordable energy that creates jobs and is environmentally friendly and resilient against natural disasters.

Q. Have you looked at how Duke ranks nationally when it comes to residential electricity bills?

A. Yes, according to the most recent data from the Energy Information Administration ("EIA"), for 2023, Duke had the fifth highest electricity bills in the nation with an average monthly residential electricity bill of $186.56 (for utilities with more than 100,000 residential customers).

Q. How did you determine this?

A. I simply calculated the average monthly revenue per residential customer for each utility and state and combined the data together. All of these calculations are included in my electric bill comparisons from the EIA 2023 data and are attached as Exhibit MM-1.

Q. Is this a standard-practice for comparing electric bills?

A. Yes, the EIA calculates the average residential electric bills itself using this methodology and compares average monthly bills across utilities and states using this method every year.

Q. How do Florida-utilities frequently do "bill" comparisons?

A. They frequently do "bill" comparisons using a standardized 1,000 kWh assumption.

Q. What's your opinion regarding that kind of comparison?

A. It is an arbitrary and misleading comparison. Consumers do not pay bills based off of 1,000 kWh of usage; they pay bills off of actual usage. Florida utilities often have higher rates above 1,000 kWh of usage, and most average above 1,000 kWh of usage. Most utilities out of state have consumers that use less than 1,000 kWh of usage. Thus, 1,000 kWh of usage frequently understates the actual bills Florida consumers pay, while overstating the actual bills others pay.

Q. Have you looked at the impact of Duke's proposed rate increase in this case?

A. Yes. Duke is proposing to increase base rates for residential customers for 1,000 kWh from a current $83.91 to $108.05 in 2027, about a $25 increase in base rates in electric bills. This is a jarring increase and can lead to an increase in energy burden for communities in the Duke Energy territory. Also, with the increase in storm activity and the volatile fuel prices, storm fees or fuel price fees can be tacked on that will make the overall bill much higher.

Q. Have you evaluated Duke's Energy Efficiency performance?

A. Yes. Although Duke has been meeting most of their goals (and, in most cases, are greatly exceeding their goals), they have been failing to meet their winter peak residential MW goals. I would note that for Florida Rising's members, the most important part of their goals are the energy reductions as that helps customers lower their electric bills, and last year, Duke exceeded those goals by 646%, as shown in Exhibit MM-2. However, compared to national averages, its savings are still rather small. A common way of comparing actual performance on energy efficiency between utilities is to look at the total amount of energy each utility saved in a year as a percent of that utility's total retail sales for the same year. This gives a fair comparison of how each utility is doing, since in absolute numbers, a small utility with excellent energy efficiency achievements won't save as much total energy as a huge utility with abysmal performance.

In 2021, the latest year for which the analysis has been completed, the national average for energy savings as a percent of total retail sales was 0.68%. SACE Energy Efficiency in the Southeast Report (March 2023), attached as Exhibit MM-3, at 4. In that same year, Duke achieved 0.09%. *Id.* at 24. Duke achieved 0.14% in 2023. I have prepared a workpaper supporting these calculations and attached it as Exhibit MM-4.

Q. Have you looked at Duke's proposals regarding its curtailable and interruptible customers?

A. Yes. I support Duke's proposed cuts. As it stands, the interruptible service and curtailable service represent almost half of Duke's spending on energy conservation. I have attached Duke's 2023 spending report as Exhibit MM-5. The Interruptible Service itself cost ratepayers $48,337,004 last year, and as residential customers represent the majority of revenue for Duke, this means most of that money is coming from residential customers. I have also attached Exhibit MM-6, which shows that these customers have not had any power interrupted or curtailed within the last five years, and Duke has no forecast for any interruptions in the future. Because Duke has sufficient resources to ensure these customers are not being interrupted or curtailed, it is hard to see the benefit of paying these customers almost $50 million a year. Therefore, I support Duke's proposal to cut the credit rates to these customers and would support even deeper cuts.

Q. Please summarize your testimony.

A. Duke's residential customers, including Florida Rising members, already pay some of the highest residential electricity bills in the nation. For many, limiting access to the energy we all need to survive in this modern day would perpetuate and exacerbate inequality, particularly for low-income and communities of color already facing systemic burdens. A fair and just energy system should ensure that all Floridians, especially the most vulnerable of us, have access to the affordable energy we need to live a quality life.

Q. Does this conclude your testimony?

A. Yes, it does.

[1] Ariel Drehobl, Lauren Ross, & Roxana Ayala, American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? at 9-13 (2020), https://www.aceee.org/research-report/u2006.

[2] Ian Livingston, *Florida is roasting in extreme heat and on pace for a record-warm year*, Washington Post (Aug. 11, 2023), https://www.washingtonpost.com/weather/2023/08/11/florida-record-heat-climate-summer/.

[3] Nat'l Oceanic & Atmospheric Admin., *NOAA predicts above-normal 2024 Atlantic hurricane season* (May 23, 2024), https://www.noaa.gov/news-release/noaa-predicts-above-normal-2024-atlantic-hurricane-season.

(Whereupon, prefiled direct testimony of Karl R. Rabago was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	))))	DOCKET NO. 20240025-EI

TESTIMONY OF KARL R. RÁBAGO

ON BEHALF OF

FLORIDA RISING AND LEAGUE OF UNITED LATIN AMERICAN CITIZENS

JUNE 11, 2024

C34-3349

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name, business name and address, and role in this matter.

A. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a Colorado limited liability company, located at 1350 Gaylord Street, Denver, Colorado. I appear here in my capacity as an expert witness on behalf of the Florida Rising ("FL Rising") and League of United Latin American Citizens of Florida ("LULAC") ("FL Rising/LULAC").

Q. Please list your formal educational degrees.

A. I earned a Bachelor of Business Administration in Management from Texas A&M University in 1977, a Juris Doctorate with Honors from The University of Texas School of Law in 1984, a Master of Laws in Military Law from the U.S. Army Judge Advocate General's School in 1988, and a Master of Laws in Environmental Law from the Pace University Elisabeth Haub School of Law in 1990.

Q. Please summarize your experience and expertise in the field of utility regulation.

A. I have worked for more than 33 years in the utility industry and related fields, following my honorable discharge from the U.S. Army, where I served as an Armored Cavalry officer and a Judge Advocate. I am actively involved in a wide range of utility regulatory and ratemaking issues across the United States. My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, Executive Director of the Pace Energy and Climate Center, Managing Director with the Rocky Mountain Institute, and

Director with AES Corporation, among others. My resume is attached as Exhibit KRR-1.

Q. Have you ever testified before the Florida Public Service Commission ("Commission") or other regulatory agencies in the past?

A. Yes. I appeared as an expert witness in Commission Docket Numbers 130199-EI, 130200-EI, 130201-EI, 130202-EI, 150196-EI, 160186-EI, 20200176-EI, 20210015-EI, and 20240026-EI. In the past twelve years, I have submitted testimony, comments, or presentations in utility proceedings in Alabama, Arkansas, Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, Puerto Rico, Rhode Island, Texas, Vermont, Virginia, Washington, and Wisconsin. I have also testified before the U.S. Congress and have been a participant in comments and briefs filed at several federal agencies and courts. A listing of my previous testimony is attached as Exhibit KRR-2.

Q. Does your experience give you insights into the responsibilities and duties of the Board in this proceeding?

A. Yes. As a public utility commissioner in Texas, I participated in making decisions on hundreds of rate review, rulemaking, and planning decisions in cases involving investor-owned, municipal, and cooperative electric and telephone utilities. Those matters ranged widely, from ministerial annual interest rate approvals, for example, to prudence and rate decisions on a $12.4 billion nuclear power plant, to mergers and acquisitions. I have appeared before hundreds of commissioners and board members in formal, informal, and educational proceedings in the years since. I have contributed to the writing and passage of laws and rules in many jurisdictions and have made a career of advancing regulatory and market opportunities for competitive alternatives to monopoly control of essential services businesses. I remain honored to have served as a utility regulator and remain deeply respectful of the public interest obligation that comes with the job.

II. OVERVIEW OF TESTIMONY AND RECOMMENDATIONS

Q. Please provide an overview of your testimony in this proceeding.

A. My focus in this testimony is on the spending and associated rates proposed by Duke Energy Florida, LLC ("DEF" or the "Company"), a wholly owned subsidiary of Duke Energy Corporation ("Duke"). I explain how DEF proposes to regressively increase economic burdens on its residential customers as a condition of electric service. DEF seeks the Commission's support in order to inflate profits for Duke.

In this testimony I point out how DEF's residential customer electric bills are already high and would, if the Commission accepts DEF's proposals, go even higher. I show how current and proposed rates excessively burden low users of electricity, who are DEF's lower income customers.

Taken as a whole, this rate application by DEF and Duke reflects an aggressive, unjustified, and unreasonable effort to increase the price that DEF customers must pay for essential electric service, with the burdens of this unjust profit taking intentionally weighted on and shifted to the Florida citizens least able to bear the economic hardships. Overall, the DEF and Duke proposal is inconsistent with sound rate making principles, including cost causation, economic efficiency, gradualism, and fair apportionment of costs.

I identify several key drivers of DEF's proposed rate increases and explain how adjustments to those proposals could mitigate some of the negative impacts on DEF's customers, improve the efficiency of DEF's rates, and encourage more efficient use of electricity by all customers.

Q. What are the key elements of DEF's proposed rates and rate increases?

A. DEF and Duke request rate increases in 2025, 2026, and 2027 of $593 million, $98 million, and $129 million, respectively. So, this case is about DEF proposing to lock in $820 million in rate increases over the next three years, cumulatively over $2 billion over three years.[1]

Q. What are the key drivers for these proposed rate increases?

A. DEF proposes the rate increases in order to pay for dismantlement and retirement, to make up for decreases in sales, to accelerate depreciation costs, to build some 1,050 MW in new generation, to significantly increase transmission and distribution spending, to extend the life of its fossil fuel generation plants, and to maintain and increase its profits.[2] As part of its generation expansion, DEF proposes to expand its "Clean Energy Connection" program, which requires ordinary customers to subsidize solar energy subscriptions primarily to benefit business and institutional customers with bill reductions.[3] And DEF also proposes to charge customers for experimental and pilot projects relating to storage and hydrogen and related projects under its "Vision Florida" spending proposals.[4]

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Q. Are the proposed rate increases by DEF driven by increased customer growth or customer use of electricity?

A. No. DEF has seen only a 1.72% cumulative average growth rate ("CAGR") in the number of residential customers over the past ten years (2013-2023), and projects only a 1.75% CAGR over the years 2024-2027.[5] DEF retail electric sales over the period 2013-2023 grew only at a CAGR of 1.51% for residential customers and are expected to decline by 0.17% over the years 2024-2027.[6] DEF's summer and winter retail peak demand grew only at a rate of 1.35% and 0.60%, respectively, over the years 2013-2023, with summer retail peak demand expected to decline by 0.36% and winter peak demand expected to grow by only 0.31% over the period 2024-2027.[7]

<u>**Table KRR-1: DEF Metrics of Growth, Historical and Projected**</u>

Cumulative Average Growth Rate (%)			
	Historical (2013-2023)	Projected (2024-2027)	Change
Residential Customer Count	1.72%	1.75%	0.03%
Residential Retail Sales	1.51%	-0.17%	-1.68%
Summer Peak Demand	1.35%	-0.36%	-1.71%
Winter Peak Demand	0.60%	0.31%	-0.29%

Q. How do DEF spending proposals stack up against DEF growth metrics?

A. DEF spending is vastly out of proportion to key DEF growth metrics. DEF proposes 69% average annual growth in transmission spending over the years 2025-2027, and 32% average annual growth in distribution spending over the same period.[8]

Table KRR-2: DEF Recent and Proposed Transmission and Distribution Spend

Transission Spending, without SPP ($ Millions)	2023	2024	2025	2026	2027	Average (2025-2027)
Total	$ 510.3	$ 578.4	$ 503.8	$ 416.2	$ 407.3	$ 442.4
Less: Growth	$ 376.5	$ 324.9	$ 272.9	$ 320.7	$ 311.7	$ 301.8
Total Net of Growth	$ 133.8	$ 253.5	$ 230.9	$ 95.5	$ 95.6	$ 140.7
Growth as % of Total	74%	56%	54%	77%	77%	69%

Distribution Spending, without SPP ($ Millions)	2023	2024	2025	2026	2027	Average (2025-2027)
Total	$ 575.1	$ 572.9	$ 571.9	$ 570.5	$ 575.6	$ 572.7
Less: Expansion	$ 199.0	$ 109.6	$ 191.2	$ 196.0	$ 200.9	$ 196.0
Less: Major Projects	$ 102.0	$ 167.6	$ 170.4	$ 212.1	$ 204.0	$ 195.5
Total Net of Growth	$ 274.1	$ 295.7	$ 210.3	$ 162.4	$ 170.7	$ 181.1
Growth as % of Total	47.7%	51.6%	36.8%	28.5%	29.7%	32%

Q. How else can the Commission appreciate DEF's overbuilding and excessive spending in Florida?

A. DEF reveals its overbuilding in generation, which also drives other costs such as transmission spending, in its extremely high reserve capacity margins.[9] DEF's loss of load probability statistics and reserve margins vastly exceed targets set with the Florida Reliability Coordinating Council as well.[10]

Table KRR-3: DEF Current and Projected Peak Reserve Margins

DUKE ENERGY FLORIDA
RESERVE MARGIN AT THE TIME OF

YEAR	WINTER PEAK: TOTAL CAPACITY AVAILABLE	WINTER PEAK: SYSTEM FIRM WINTER PEAK DEMAND	WINTER PEAK: RESERVE MARGIN		SUMMER PEAK: TOTAL CAPACITY AVAILABLE	SUMMER PEAK: SYSTEM FIRM SUMMER PEAK DEMAND	SUMMER PEAK: RESERVE MARGIN	
	MW	MW	MW	% OF PEAK	MW	MW	MW	% OF PEAK
2023	12,359	8,204	4,155	51%	11,843	8,270	3,574	43%
2024	12,244	9,163	3,081	34%	11,371	8,899	2,473	28%
2025	12,028	8,954	3,074	34%	11,793	8,728	3,065	35%
2026	11,807	8,979	2,828	31%	11,773	8,814	2,959	34%
2027	11,984	9,004	2,980	33%	10,929	8,868	2,062	23%

DUKE ENERGY FLORIDA
WITHOUT THE 2023-2027 COMBINED CYCLE HEAT RATE UPGRADES, THE 2025-2027 SOLAR ADDITIONS, AND THE 2027 BATTERY ADDITIONS
RESERVE MARGIN AT THE TIME OF

YEAR	WINTER PEAK: TOTAL CAPACITY AVAILABLE	WINTER PEAK: SYSTEM FIRM WINTER PEAK DEMAND	WINTER PEAK: RESERVE MARGIN		SUMMER PEAK: TOTAL CAPACITY AVAILABLE	SUMMER PEAK: SYSTEM FIRM SUMMER PEAK DEMAND	SUMMER PEAK: RESERVE MARGIN	
	MW	MW	MW	% OF PEAK	MW	MW	MW	% OF PEAK
2023	12,359	8,204	4,155	51%	11,843	8,270	3,574	43%
2024	12,244	9,163	3,081	34%	11,371	8,899	2,473	28%
2025	11,928	8,954	2,974	33%	11,569	8,728	2,840	33%
2026	11,598	8,979	2,619	29%	11,290	8,814	2,476	28%
2027	11,598	9,004	2,594	29%	10,320	8,868	1,452	16%

Q. Can the impacts of DEF historical spending be seen in DEF residential customers' average bills?

A. Yes. Based on data that DEF submits to the U.S. Energy Information Administration ("EIA") and reported as of 2023, average DEF residential bills are about $187 per month based on average monthly usage of about 1,034 kWh per month.[11] This places DEF residential bills fifth highest in the nation among utilities with more than 100,000 residential customers, and the proposed increases would take bills even higher.

Q. What does DEF propose for residential energy and demand charges over the next three years?

A. DEF proposes to increase residential energy and demand charges, which are collected through a single volumetric rate, by between 21% and 34%, depending on the season and usage level. DEF proposes that these increases be applied regressively, with more of the increase going to low users of electricity, who are often lower-income customers as well.[12]

Table KRR-4: DEF Proposed Residential Energy and Demand Charge Increases

Usage Level / Season	2024	2025		2026		2027		Cumulative
Rate in Cents/kWh	Rate	Proposed Rate	% Increase (YR)	Proposed Rate	% Increase (YR)	Proposed Rate	% Increase (YR)	% increase (2025-27)
0 - 1,000 KWH (Winter)	7.919	8.867	12.0%	9.085	2.5%	9.559	5.2%	20.7%
Over 1,000 KWH (Winter)	9.088	10.308	13.4%	10.531	2.2%	11.019	4.6%	21.2%
0 - 1,000 KWH (Non-Winter)	6.830	8.448	23.7%	8.703	3.0%	9.160	5.3%	34.1%
Over 1,000 KWH (Non-Winter)	7.730	9.156	18.4%	9.403	2.7%	9.848	4.7%	27.4%

Q. What recommendations do you offer in this testimony to address these issues and DEF's proposals to further increase customer bills for electricity service?

A. In this testimony, I present a number of recommendations designed to reduce the outsized electric bills and energy burdens faced by DEF's residential customers. These recommendations include:

(1) Ending use of the residential minimum bill and replacing it with a customer charge based on basic customer cost;

(2) Reducing DEF's ROE to 9.50%;

(3) Disallowing use of the proposed method for cost allocation and substitute a 12 CP and 50% AD cost allocation, without using the principal of "gradualism" to shift additional costs onto residential customers;

(4) Eliminating growth, expansion, and major project spending for transmission and distribution unless and until a benefit cost analysis ("BCA") is completed;

(5) Eliminating spending for Vision Florida projects unless and until a BCA is completed;

(6) Requiring DEF to produce BCAs to support all requests for capital spending projects for $1 million or more.

III. FOUNDATIONAL DATA ON FLORIDA RESIDENTIAL ELECTRIC BILLS

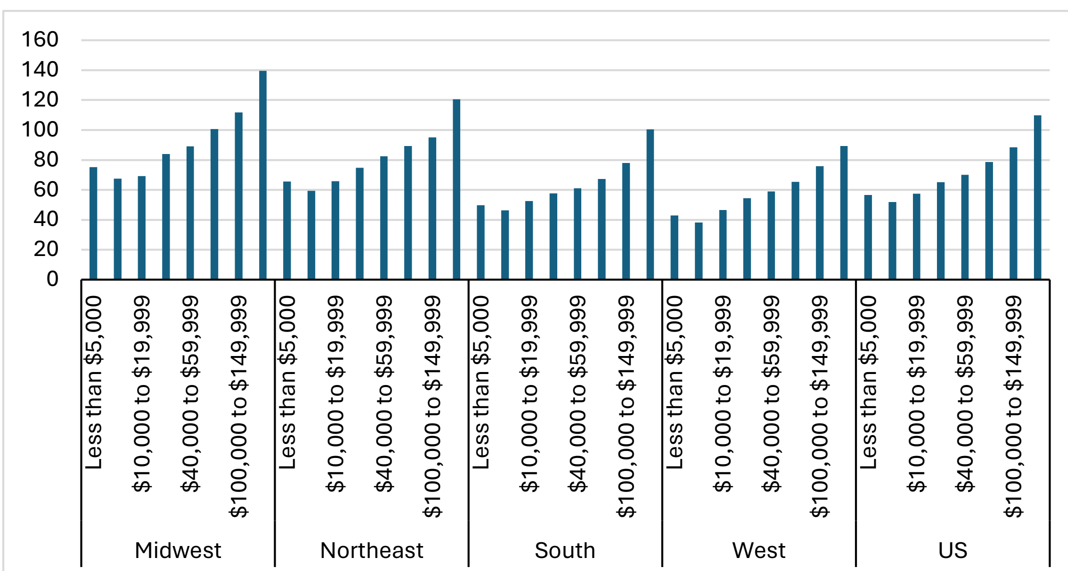
Q. Why are you focused on electric bills for residential customers?

A. Improvements in affordability are a core objective for Florida Rising and the League of United Latin American Citizens. All Florida customers must use electricity to survive—to provide air conditioning and heat, and in the future, to provide motive power for transportation and thermal energy for processes and cooking. In high-use parts of the country like Florida, rates alone are not a meaningful or satisfactory indicator of electric utility performance. Utility energy bills, and bills as a percentage of household income—an affordability metric known as energy burden—are a key indicator of fairness, reasonableness, and justice. Affordability must be a key performance metric for DEF and any electric service provider.

Q. What do we know about average residential electricity usage in Florida?

A. According to the EIA data, which relies on inputs submitted by DEF and other utilities, the average monthly level of electricity usage by DEF residential customers in Florida is 1,034 kilowatt-hours ("kWh") per month.[13] Lower-income customers across the U.S., on average, use less energy but spend a greater percent of their income on energy costs compared to higher-income customers. According to 2020 EIA Residential Energy Consumption Survey ("RECS") data,[14] there is a clear correlation between income and electricity use, with lowest income customers consuming as little as half as much energy annually compared to their wealthiest counterparts. Florida is in the South region and South Atlantic sub-region. The correlation between energy use and income level is also true in Florida.

<u>Figure KRR-1: U.S. Mean Annual Household Energy Consumption by Income Category and Region 2020, million Btu)</u>



Lower income customers, despite using less energy, also suffer from a higher energy burden than higher income customers—their energy bills constitute a higher share of their household income.

Q. Why is it important to understand when customers have high energy burdens?

A. Customers with high energy burdens are vulnerable to rate and bill volatility. Month-to-month changes in rates that might not frustrate the household budgets of well-to-do customers can cause rate shock to customers with high energy burdens. Low-income customers often live on the edge of economic or energy insecurity—an inability to meet basic household energy needs that is sometimes referred to as the "heat (or cool) or eat" dilemma.[15] An unaffordable electric bill can create a long-lived cascade of household economic problems, made worse with pancaking fees and charges from utilities and other businesses. Energy insecurity is not just an economic issue, but a social and public health matter as well.[16] For these and other reasons, understanding customer energy burdens informs the prudence and adequacy of the generation supply mix that a default service provider assembles on behalf of customers.

Q. What does the data tell us about energy burdens in Florida?

A. The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy has created a Low-Income Energy Affordability Data Tool ("LEAD Tool") that documents key affordability metrics across the U.S.[17] The latest data is from 2020 and shows that at that time, nearly one million Florida households had income levels below 100% of the Federal Poverty Level, [18] and nearly 2.4 million Florida households had income levels below 200% of the Federal Poverty Level. According to the Florida Department of Health, the number of Floridians living in poverty grew to 2,725,633 in 2022, based on U.S. Census data.[19]

The LEAD Tool data, provided in Table KRR-5, shows that while the overall electricity energy burden in Florida is about 2%—meaning 2% of total household income is spent on electricity—the energy burden for customers at or below the poverty level is seven times higher, at 14%, and is three and one-half times higher, at 7%, for Floridians with household incomes at or below twice the poverty level. Even for households with income up to 400% of the poverty level, the electricity energy burden is 50% higher than the statewide average, as shown in Figure KRR-2.

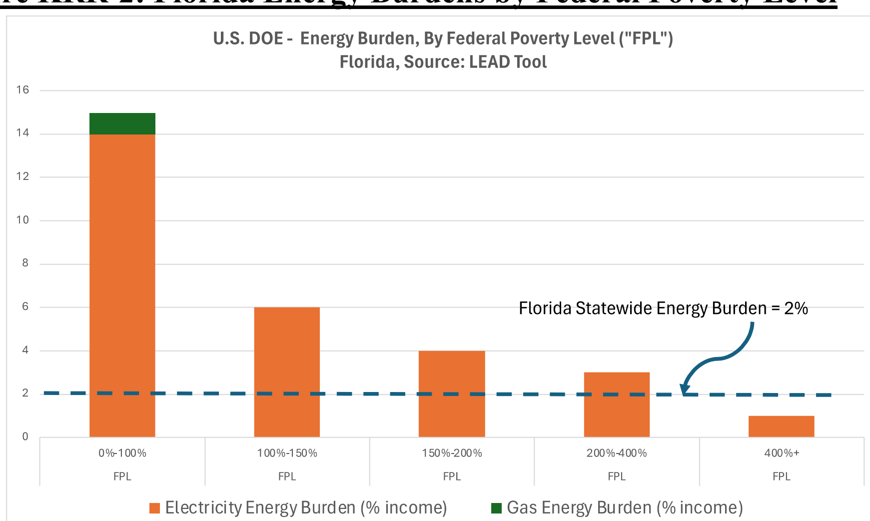
Table KRR-5: Households and Energy Burdens at or below 100% and 200% of Federal Poverty Level

	Households	
	Below 100% FPL	Below 200% FPL
Energy Burden (FL avg = 2%)	14%	7%
Annual Energy Cost	$ 1,428	$ 1,474
2020 Annual Income	$ 10,096	$ 21,868
Number of Households	935,353	2,385,449

Federal Poverty Level (FPL) - 2020	Household of 1	Household of 4
100% of FPL	$ 12,760	$ 26,200
200% of FPL	$ 25,520	$ 52,400

Federal Poverty Level (FPL) - 2024	Household of 1	Household of 4
100% of FPL	$ 15,060	$ 31,200
200% of FPL	$ 30,120	$ 62,400

Figure KRR-2: Florida Energy Burdens by Federal Poverty Level



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Q. How do high energy burdens translate into energy insecurity and energy injustice?

A. For DEF's customers living at or below the poverty level, or even twice the poverty level, there is little or no room in the household budget for unexpected costs or for meeting the increased energy demands of hotter summers and extreme weather events. A $30 added household expense, for example, is one week's worth of electricity for a customer with a monthly bill of $120 and could require months of scrimping and saving to recover from. More importantly, distributional inequity in the levying of new charges and rate increases has an outsize impact on highly burdened households.

Q. Can't highly burdened households cut back on energy use or use energy more efficiently to reduce their electric bills or the impact of those bills on household budgets?

A. No. Energy efficiency measures cost money, and even spending an extra $20 on efficient light bulbs is beyond the financial ability of household budgets facing high energy burdens. The housing that low-income customers live in is as a rule highly inefficient. Customers in rental properties have no control over the aspects of their homes that contribute most to cooling and heating bills—insulation, air conditioner and heater efficiency, windows, and major appliances. Many low-income customers are also on fixed incomes and already practice energy rationing—there is little or no room for further curtailment, especially for the elderly and infirm.

Q. What does DEF know about its customers' household income levels?

A. Apparently, nothing. DEF says it "does not track or maintain information around . . .

income level" of its customers.[20]

Q. What does DEF say about the importance of maintaining affordable rates for its residential customers?

A. DEF president Melissa Seixas does not mention affordability in her testimony. No DEF witnesses address customer affordability challenges or energy burdens or the impact that DEF's proposed rates will have on highly burdened customers.

Q. In the face of the basic facts, what has DEF proposed in this rate increase application?

A. DEF proposes to increase rates and continue to recover them through an unconscionably regressive assignment of those costs to its customers who can least afford the burden, including through its residential minimum bill. As shown in Table KRR-6, the lowest users of electricity—who are also amongst DEF's least-wealthy customers—pay an effective rate more than 300% higher than the biggest users.

Table KRR-6: DEF Present and Proposed Effective Rates by Usage Level, in Cents/kWh

Usage	Cents/kWh	
KWH	Present	Proposed
0	0.0	0.0
100	31.2	32.3
250	17.9	18.4
500	13.4	13.8
750	12.0	12.3
1,000	11.2	11.5
1,250	10.8	11.0
1,500	10.5	10.7
2,000	10.1	10.3
3,000	9.8	9.9

IV. DEF'S MINIMUM BILL FOR RESIDENTIAL CUSTOMERS SHOULD BE ELIMINATED AND DEF SHOULD USE THE BASIC CUSTOMER METHOD TO SET FIXED CUSTOMER CHARGEDS

Q. What is your recommendation to the Commission regarding DEF'S $30 minimum bill for residential customers?

A. The Commission should order DEF to eliminate its residential minimum bill because it is unjust, economically regressive, and inconsistent with efficient rate design. The Commission should further order DEF to use the basic customer method to set a fixed residential customer charge and prohibit use of minimum distribution system method to classify demand-related costs as customer costs.

Q. What would DEF's fixed customer charge be under your recommendations?

A. I cannot calculate the exact residential customer charge because the charge will be impacted by my recommendations for a lower return on equity ("ROE"), a change in the basic cost of service allocation method used, reductions in distribution spending, reductions in customer service costs classified as customer costs, elimination of uncollectible costs from customer costs, and other adjustments—all of which could impact the customer charge and depend on Commission decisions. However, I can state that under DEFs proposed rates and spending levels, it calculates a residential fixed customer charge of $13.67 per customer per month under its proposed 12 Coincident Peak and 25% average demand ("12CP & 25% AD") allocation methodology,[21] and this should be the upper limit of a just and reasonable fixed customer charge for residential customers. Under existing rates, DEF's residential fixed customer charge is $12.61 per customer per month,[22] which DEF proposes to increase by about 8.4%.

Q. How does DEF's minimum bill impact residential customers?

A. For some 66,000 of its residential low users of electricity,[23] who are more likely to be low-income customers, and for some 26,000 or 30% of customers seeking to reduce their excessive DEF bills by installing residential solar, DEF's minimum bill is a fixed customer charge. The rate is unjust and inconsistent with cost causation principles and has economically regressive impacts on low-income customers, as I discuss further in this testimony. It discourages investment in energy efficiency, distributed generation, distributed storage, and other distributed energy resources.

Q. How does DEF justify its use of the minimum bill approach?

A. DEF makes several arguments for its minimum bill,[24] all of which are fundamentally flawed. First, DEF argues that the minimum bill ensures that customers contribute to fixed cost recovery at a level that lower usage would not capture. This argument is flawed because it assumes that demand-related fixed costs should be recovered regardless of usage. Low users create lower fixed costs above those created by the customer's basic connection to the grid—and the latter are properly recovered in a fixed customer charge calculated based on the basic customer method. Second, DEF argues that seasonal customers don't pay their fair share of fixed costs under traditional rate design, so a minimum bill is necessary to prevent unfair cross subsidies. This argument is both cynical and flawed because DEF's unjust solution is to impose a minimum bill that forces year-round low users of electricity—the poor and those on low fixed incomes—to pay fixed costs that they do not cause. Third, DEF argues that the minimum bill helps avoid increases in the fixed customer charge that would otherwise be needed to recover demand-related fixed costs. Again, the flaw in this argument is that it assumes that demand-related fixed costs should be recovered in the fixed customer charge. The argument carries no weight when only true customer costs are included in the fixed customer charge. Fourth, repetitively and most cynically, DEF argues that if it could not impose a minimum bill on all customers who, due to economic hardship, rooftop solar investment, or lifestyle, use less than the average for all customers in the class, it would be forced to dramatically increase customer charges to recover demand-related costs that these customers do not create. And if DEF used fixed customer charges to collect these demand-related costs through fixed customer charges, it argues, volumetric charges would be reduced, which would weaken support for energy efficiency programs.[25]

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Q. If different rate designs ultimately collect the same amount of total revenues, does it matter how those revenues are collected?

A. Yes, very much so. Fixed charges, which is how a minimum bill operates for low users of electricity, are inherently regressive—they have greater cost impact on low users that are often also low-wealth customers. Guaranteeing non-bypassable revenues through high fixed customer charges or a minimum bill is extremely desirable to DEF and Duke in order to meet the expectations for continuous profits promised to investors. Keeping volumetric rates lower with a minimum bill keeps consumption and growth rates up because it weakens the incentive for efficiency. Guaranteeing recovery of fixed costs associated with infrastructure spending, which occurs when these costs are recovered through a non-bypassable fixed customer charge, creates an incentive for the utility to increase that kind of spending. Increasing fixed non-bypassable charges or imposing a minimum bill has an impact on the cost-effectiveness of energy efficiency, distributed generation, and other distributed energy resource ("DER") investments by customers because higher non-bypassable charges means lower volumetric rates, or in the case of a minimum bill, a floor on bill savings. This results in longer payback periods on customers' investments designed to reduce usage of energy. In sum, the decision about whether to recover costs through fixed charges and/or a minimum bill is a decision about what price signals the rate sends—both to customers and to the utility; it is a fundamental question of rate design.

Q. Why do you say that high fixed charges and the minimum bill for residential electric are economically regressive?

A. It is a matter of simple math that high fixed charges and the minimum bill have greater impacts on low users of electricity and gas services because more of their monthly bill is fixed and non-bypassable. These impacts become economically regressive when there is a high correlation between low usage rates and lower household incomes. My testimony has demonstrated that this correlation exists in Florida and among DEF's customers.

Q. Are there other disparate impacts from high fixed charges to underrepresented customer groups?

A. Yes. In my experience, low users of electricity have lower and flatter load curves—less peaky demand—than high users. As a result, when peak-driven demand-related fixed costs are allocated to the residential class and some of those costs are included in a minimum bill or collected through a fixed customer charge set under a minimum distribution system method, low-use, often low-wealth customers are required to pay more than their fair share of these costs. As a result of DEF's reliance on the minimum bill approach, low-wealth customers are being charged for costs driven by the usage levels and patterns of more well-to-do, higher-demand customers. Simply stated, low-use and often lower demand customers are being required, through the minimum bill, to subsidize higher-use customers who are typically more well-to-do.

Q. As high fixed cost businesses, should utilities impose high fixed charges or a minimum in order to align rate structure with cost structure?

A. No. As I previously addressed, DEF's justification for a minimum bill asserts that it should charge high fixed customer charges because it has high fixed costs and because low users pay lower bills than average customers and thus contribute less to total fixed cost recovery. In my more-than thirty years in utility regulation I have yet to find a single authoritative economic text to support the argument that economic efficiency results from mimicking cost structure in rate design. Moreover, DEF assumes that customers at all usage levels cause the same average amount of fixed costs—a proposition it does not support with cost-of-service data.[26] On the contrary, the flatter usage patterns of low user customers and the generation coincidence of self-generation customers that I have seen supports at least a working assumption that low users create lower levels of fixed costs than high users. Distribution infrastructure and component costs, which are typically sized to demand, are typically lower for lower use customers.

Q. Are there competitive businesses with high fixed costs that impose high fixed charges?

A. There are very few. The vast majority of high fixed-cost businesses do not impose fixed charges at all and would likely not survive long in a competitive market if they did. For example, neither airlines nor transit services require monthly subscriptions, nor do hotels or shopping malls. There are some businesses like warehouse retailers and on-line shopping services with optional levels of fixed charges, but those charges appear designed to increase sales to loyal customers—which, in the electric utility regulatory setting, would be called "load building." The fact that many businesses must make large fixed-cost investments does not translate into fixed charges in almost all business cases; rather, the forces of competition reward businesses for careful investment analysis, inventory management, and cost control—all disciplines that if mastered would greatly improve the performance of electric and gas utilities far more than a guarantee of fixed costs recovery through non-bypassable customer charges.

Q. Isn't economic efficiency improved when prices reflect marginal costs?

A. Yes, prices advance efficiency when they reflect marginal costs, but that is an entirely different issue than reflexively asserting that fixed charges should be used to collect marginal fixed costs as a matter of rate design. In fact, by weakening the price signal that customers see from marginal changes in consumption at very low levels of use, the minimum bill approach regressively deviates from marginal cost pricing.

Q. How has DEF analyzed price signal impacts from its minimum bill for electric customers?

A. DEF provided "typical bill" calculations of the bill impacts of its rate proposals via MFR filings and reports that more than 90,000 of its residential customers pay more than they should by operation of the minimum bill,[27] but it has not otherwise studied the impacts of its proposed rates on residential customers, or upon low-wealth customers in particular.

Q. What costs should be charged on a per-customer basis?

A. First, I note that there is no rule of economics that requires any per-customer fixed charge. There are many competitive businesses that recover costs only through usage-based charges. Where a customer charge is used, a good rule of thumb is this: If the cost disappears because the customer leaves the system, the cost is a customer cost. This is generally referred to as the "basic customer method." The consumption function of the meter, the service drop, and a reasonable share of customer service spending would all meet this test, and therefore these costs are included in approaches like the basic customer method. Likewise, if the cost remains after a customer leaves the system, the cost is not a customer cost. Transformers, secondary and primary distribution lines, program-specific marketing and customer care expenses, uncollectible bills, general operations, administrative and maintenance expenses, and taxes are all non-customer costs, and the principle of cost-causation dictates that those costs should not be recovered through a fixed or customer charge or a minimum bill.

Q. Are there any well-accepted references that comport with your view that the basic customer method is most appropriate for use in classifying customer costs?

A. Yes. In 1961, James C. Bonbright defined customer costs as follows:

> [The customer costs] are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer.[28]

Simply stated, Bonbright's definition—which describes the basic customer method—ensures that the customer charge should be limited to the marginal cost of connecting the customer to the grid and should include only costs that vary directly with the number of customers.[29] A minimum bill approach violates this long-standing principle.

Q. Are there any benefits to relying on Bonbright's definition of customer costs in building the customer charge?

A. Adhering to the principle that customer costs are costs that vary with customer count, and almost or entirely without regard for usage, advances other ratemaking principles such as equity and cost-causation and preserves the power of volumetric charges as a price signal. Residential customers who do not have to pay a minimum bill can see a direct correlation, both positive and negative, between their level of usage and their contributions to cost creation when energy- and demand-related costs are recovered through volumetric charges. Allocating demand-related costs or even unallocable costs (as Bonbright viewed the minimum system costs) to the fixed customer charge eliminates, or at least severely weakens, the price signal impact.

Q. How much cost does connecting a new customer cause?

A. Costs directly related to grid connection for new customers include a portion of the cost of a meter, billing and metering services, and collection costs—in Bonbright's words, the costs the utility "must incur in taking on another customer."[30] According to DEF's data, this amount is less than $14.00 per month.[31]

Q. What should DEF do to determine customer-related costs and ultimately build a just and reasonable customer charge?

A. The Company should use the basic customer method. The Regulatory Assistance Project Cost Allocation Manual provides additional explanatory detail that the Company should consult.[32]

Q. Does DEF's minimum bill raise any other economic efficiency concerns?

A. Yes. The minimum bill approach sends the wrong economic price signal to DEF. When marginal distribution infrastructure costs are allocated to high fixed charges or a minimum bill, demand elasticity means that sales will go up as customers face lower marginal rates for increased use. In this way, a Commission decision to limit the costs that can be loaded into fixed charges or to disallow a minimum bill serves as the classic substitute for the forces of free market competition. Conversely, the utility that is allowed to increase spending and allocate those costs to non-bypassable charges like the minimum bill will have less incentive to operate and spend in a least-cost manner. Revenues that a regulated monopoly can extract from customers without fear or with reduced fear of consumption changes are called monopoly rents—neither markets nor regulatory commissions should encourage them by allowing high fixed charges or minimum bill rate designs.

Q. What do you conclude about DEF's minimum bill for residential customers?

A. DEF's minimum bill, as and like a high fixed customer charge, unjustly and unreasonably charges customers for costs that are not customer costs, and it is a bad rate making policy.

Q. What residential fixed customer charge should the Commission approve?

A. The Commission should approve a fixed customer charge for residential customers that eliminates the minimum bill and is not based on treatment of demand-related costs as customer costs. Again, that charge should not be higher than $14.00 per customer per month, and with other reductions in allowed revenue that I propose, should be substantially lower.

Q. How do you propose that DEF recover demand-related costs that should not be recovered through the minimum bill or through high fixed customer charges?

A. I propose that the adjustments be addressed in a revenue neutral manner. That is, any just and reasonable costs that are not collected through the customer charge should be assigned as demand-related and recovered through the residential volumetric charge.

Q. What effect does the classification of demand-related distribution costs have on volumetric rates?

A. My proposal has three primary impacts. First, it removes a significant amount of the regressive nature of DEF's minimum bill and better aligns overall rates with cost causation. This change empowers low-use and low-income customers to better manage their electric bills through changes in usage and behavior. Second, it increases the volumetric rates, sending a more efficient price signal to high users and reflects the fact that high users drive distribution system costs. This in turn improves the economics of efficient use and efficiency programs, self-generation, and reliance on zero- or low-marginal cost resources like solar energy. Third, the changes will send better price signals to DEF relating to its level of distribution spending.

V. DEF'S ROE PROPOSAL IS EXCESSIVE AND UNJUSTIFIED AND SHOULD BE REDUCED

Q. What allowed ROE and equity fraction does DEF propose?

A. DEF proposes a midpoint allowed ROE of 11.15%, with potential for earning up to 12.15% in this rate proceeding.[33] DEF also proposes a 53% equity ratio from investor sources.[34]

Q. How does DEF justify its ROE request?

A. After reviewing the testimony submitted by DEF, primarily that of Company witness

Adrien McKenzie,[35] DEF's primary witness on the topic, DEF's argument boils down to the that fact it wants to spend a lot of money and that it wants to make a lot of money in doing so. DEF presents no evidence of financial impairment or difficulties in obtaining capital at reasonable rates. As discussed in this testimony, a significant amount of DEF's proposed spending is excessive and unjustified. Although DEF witness McKenzie modifies and applies several analysis models to argue that the proposed ROE and capital structure are reasonable,[36] his arguments can be boiled down to one, in three parts:[37] (1) DEF operates in a storm-prone region due to the accelerating effects of climate change, which is risky, and repairing systems damaged by severe storms is expensive; (2) DEF proposes to spend a huge amount of money on infrastructure and other projects; and therefore (3) DEF needs to provide capital investors with outsized profits in order to get the capital it needs to fund its risky and aggressive expansion and spending plans.

Q. Do you agree with these justifications?

A. No, and for several reasons. As I have testified, DEF's primary business drivers of customer and sales growth have been extremely modest in effect and do not justify the dramatic increases in spending and earnings that DEF has had and proposes. DEF is overspending and thus over-earning against these drivers—its spending and profits should be reduced, not further inflated. Second, DEF's proposed new spending is unreasonable and unjustified in many cases. If these proposals were moderated to reasonable levels, DEF could maintain strong financials without making outsized profits. DEF wants to increase rates by about $820 million over 2025, 2026, and 2027 (cumulatively over $2 billion) primarily based on new capital projects, growing its rate base and profits. Third, DEF's ROE proposal is out of step with awarded ROEs in recent years. According to the Edison Electric Institute ("EEI"), awarded ROEs since the start of 2022 have averaged 9.52%, as have awarded ROEs dating back for five years.[38] In fact, awarded ROEs over the past ten years have been only slightly higher, at 9.67%.[39] Fourth, the Federal Reserve Bank is continuing efforts to control inflation and resume interest rate reductions.[40] Fifth, while DEF faces climate change risks associated with severe weather events, such risks are now unfortunately common across the U.S. and around the world. DEF has finally started taking some inconsistent steps towards reducing its dependence on fossil fuels, and if it is serious about climate risk, it should continue those efforts.[41] In addition, if DEF wants to protect investors, it should not do so with outsized profits for a risky system, but through concerted planning and efforts to change the basic structure of its system. These efforts include more aggressive support, tested by cost-effectiveness analyses, for deployment of distributed energy resources such as distributed storage, distributed generation, energy efficiency, strengthened building codes and standards, and other similar measures.

Q. Why, in particular, isn't increasing DEF profits a solution for increased climate-related severe weather events?

A. Climate-related severe weather events don't just impact DEF. They create massive problems throughout local and national economies and society as a whole. To propose that DEF profits be increased on the backs of DEF's customers, especially residential customers, in order to compensate DEF for the risk of running an overwhelmingly fossil-fueled electric utility ignores the very real suffering and hardships imposed on those customers all year round. In this case, DEF proposes increases in climate-damaging fossil fuel emissions and excess profits on those increases. Regulation that acts as a substitute for competition should not and would not award excess profits for excessively risky investments and behavior.

Q. Would significant reductions in DEF's proposed spending reduce the need for excess profits?

A. Conveniently, while DEF asserts that excessive spending plans justify a higher ROE, DEF also asserts that reducing that spending will not reduce the need for outsized profits.[42] I don't agree, but from a performance perspective, I could support the Commission's consideration of a well-developed proposal that would allow DEF to earn at the profit levels it proposes in return for achieving a significantly reduced level of capital and operating spending. Until DEF puts that proposal on the table, its allowed ROE should be reduced dramatically.

Q. What allowed ROE do you recommend that the Commission approve for DEF?

A. Unless and until DEF shows that it is not seeking to grow Duke profits on the backs of Florida residents, and it offers a comprehensive plan for mitigating and not exacerbating its contributions and exposure to climate-related severe weather, DEF's allowed ROE should not exceed the average awarded to other utilities. For these reasons, I recommend that the Commission award DEF a midpoint ROE of no higher than 9.50%.

Q. What impact would an allowed ROE of 9.50% have on DEF's revenue requirements and rates?

A. Based on the information provided by DEF in this case, I estimate that an allowed ROE of 9.50% would reduce the overall cost of service by about 4.6%. According to

DEF,[43] a reduction in the allowed ROE from 11.15% to 9.50% will reduce DEF's total residential retail cost of service by about \$100 million, and the residential retail cost of service by about \$132 million—providing a significant improvement in electric service affordability. As I explain in the next section of this testimony, I also recommend that the Commission direct DEF to employ a 12 CP 50% AD method for cost allocation, which would further reduce the cost of service for residential customers and more fairly allocate costs.

VI. DEF'S PROPOSED 12 CP 25% AD COST ALLOCATION METHOD OVER-ALLOCATES COSTS TO RESIDENTIAL CUSTOMERS AND THE COMMISSION SHOULD DIRECT DEF TO USE A 12 CP 50% AD METHOD IN ITS PLACE

Q. What impact does DEF implementation of a 12 CP 25% AD allocation method for production and demand-related retail costs have on residential customer rates and affordability?

A. DEF expresses a preference for the 12 CP 25% AD method over the 12 CP 1/13 AD method it also analyzed because the 25% AD method assigns greater weight to energy use than the 1/13th method.[44] While this approach reduces the cost assignment to residential customers somewhat, it does not go far enough. I therefore recommend that DEF use a 12 CP 50% AD method.

Q. What factors are considered when deciding which allocation method to use?

A. Although arguments and justifications about which cost allocation method to use are often couched in broad assertions about which method better reflects cost causation, the decision of how to slice the pie of total revenue requirements often devolves to a contest of regulatory political power played out in confidential settlement negotiations. Very large customers with the ability to fully participate in rate proceedings represented by expensive consultants often do better than residential consumer advocates with limited budgets. It is also true that because the number of residential customers and small business customers vastly exceeds the numbers of customers in other classes, assignment of revenue requirement increases to small customers can result in smaller per-unit or per-bill increases relative to other customer classes. Additionally, under a somewhat perverse and certainly unjust theory of inverse elasticity, monopoly utilities often find convincing the argument that excess costs should be assigned to customers with the least opportunity to do anything but pay the charges.[45]

Q. Why do you recommend the 12 CP 50% AD approach?

A. In my opinion, the best measure for which cost allocation method to use is which best serves and promotes the public interest. Solar generation provides relatively high contributions to capacity value at relatively small levels of system penetration, but is primarily valuable as a zero-marginal cost generator of energy. Given that solar production costs are driving so much of capital expenditures, and that increasing deployment of solar means a reduced contribution to system peaks in both summer and winter, a heavier weighting on the energy aspect—using a 50% rather than 25% factor—is more appropriate to capture residential cost contributions to system costs.[46] I recommend using a 12 CP & 50% AD methodology without MDS, and without a minimum bill, as reflected in Exhibit KRR-3 (reflecting my recommended 9.5% ROE with no other additional changes, although other costs should be disallowed as discussed below), and that the Commission direct DEF to adjust rates accordingly.

Q. What is the combined effect of your recommendations that the Commission only allow DEF an ROE of 9.5% and that it use a 12 CP 50% AD cost allocation method?

A. The cumulative effect of these two recommendations would be the reduction of the residential retail cost of service by about 5.7% or $122 million in residential cost of service, again, with accompanying improvements in affordability.

VII. DEF's PROPOSED EXPANSION OF THE CLEAN ENERGY CONNECTION PROGRAM INCREASES CROSS-SUBSIDIZATION OF BUSINESS CUSTOMERS BY RESIDENTIAL CUSTOMERS

Q. What does DEF propose regarding its Clean Energy Connection program?

A. DEF proposes to add five new solar generation plants to its Clean Energy Connection ("CEC") program in the years 2025-2027.[47] The program expansion will add about $1.7 billion to DEF's revenue requirements.[48]

Q. How does DEF structure the CEC program in terms of costs and benefits?

A. DEF's program is a subsidy program designed overwhelmingly for the benefit of large customers that entitles those customers to solar production credits that cost less than those customers are required to pay in program subscription costs.[49] Shortfalls in the costs are paid for by non-subscriber customers, who are primarily residential customers. DEF asserts that if its projections of fuel and emissions costs savings are realized as expected, the program pays for itself, but only when such savings over the next thirty years are counted.

Q. Is the CEC program reasonable and equitable?

A. No. If residential customers are going to be required to pay for new solar generation, they should receive 100% of the benefits. If business customers want to subscribe to a solar program, they should pay 100% of the program costs. And any risks of unrealized savings should be allocated to the program subscribers. The Commission should not allow DEF to force additional inter-class subsidies through the CEC program.

Q. How do you recommend that the Commission respond to DEF's proposal to expand its CEC program spending?

A. A fairly designed community solar program can offer solar subscription benefits to customers without cross-subsidies to businesses that do not need them and without requiring non-subscribers to bear programmatic risks associated with the realization or non-realization of projected savings. The Commission should require DEF to suspend any plans for CEC program expansion unless and until DEF redesigns the program to eliminate cross-subsidies and the assignment of program cost risks to non-subscribers.

VIII. DEF PAYMENT FOR CURTAILABLE LOADS ARE UNJUST AND UNREASONABLE IN LIGHT OF OVERBUILDING

Q. Does DEF make payments or provide bill credits to large customers for participation in interruptible load programs?

A. Yes. As filed in response to discovery in the DSM goal-setting docket, over the years 2025-2027, DEF proposes to make incentive payments to customers on curtailable and interruptible rates of about $54 million each year for a total of $162 million (attached as Exhibit KRR-4). This amount reflects about an 11% increase in incentive payments over the amount paid in 2023 (see attached Exhibit KRR-5).

Q. What is the rationale for such payments or credits?

A. Curtailable rate credits or payments are generally designed to afford a utility the opportunity to realize load reductions as a cost-effective alternative to operating more expensive peak generating plants.

Q. How does DEF approach the procurement of cost-effective on-peak generation and curtailable load?

A. DEF's approach is to make curtailable rate payments or credits to large customers for service that is never curtailed and to socialize the costs to all customers that bear any of the costs of peak demand.[50] In addition, DEF has a strategy of dramatically overbuilding generation capacity and maintaining excessive peak reserve margins as a more expensive alternative to reliance of actual curtailment of large customer loads.[51]

Q. Are DEF's curtailable load payments or credits and resulting rates fair, just, and reasonable?

A. No. DEF's curtailable load payments or credits constitute costs that are neither useful nor used in providing cost-effective electric service to its customers. To the extent that the costs of the curtailable rate payments or credits are recovered from any customers other than those receiving the payments, they are nothing more than an unjust cross-subsidy.

Q. What Commission action do you recommend regarding DEF's curtailable rate payments or credits?

A. It is important for the Commission to recognize that curtailable rate programs—also known as demand response programs—can be a cost-effective alternative to building expensive on-peak generation resources. Regulatory authorities like the Commission are traditionally charged with serving as a substitute for the forces of market competition that a monopoly utility would, but for its monopoly franchise, otherwise face. As such, the Commission should require DEF to demonstrate that it is proposing to charge customers for the most cost-effective of the options it has available in meeting the demand for reliable electric service. I therefore recommend that the Commission direct DEF to suspend any curtailable rate payments to any customers until DEF has affirmatively demonstrated the cost-effectiveness of the rate under a BCA *and* that DEF be prohibited from recovering the cost of new generation or energy storage technologies designed to meet on-peak demand unless such options are also demonstrated to be the most cost-effective.

IX. DEF CUSTOMER FUNDING OF NEW BOILERS AND ONGOING $1 MILLION PER YEAR SUBSIDY TO THE UNIVERSITY OF FLORIDA IN ORDER TO MAINTAIN LOAD

Q. Please describe DEF's current contractual relationship with the University of Florida ("UF").

A. DEF has long operated the boilers at UF which in turn power a cogeneration facility and provide electricity and steam to the campus. In 2023, DEF and UF agreed that DEF would replace the existing boilers which were UF-owned, with new boilers and, in addition, DEF would continue providing UF with a $1 million/year subsidy on the cost of steam.[52] The new boilers and the subsidy will cost some $30 million which DEF proposes to recover from customers, and which DEF deems appropriate because it enables DEF to maintain 50 MW in load.[53]

Q. Has DEF conducted any analysis to validate its assertion that the costs of the new boilers and the $1 million steam subsidy are cost-effective for DEF's customers?

A. No.[54] DEF's assertions are therefore unreasonable. As it stands, the public education institution should operate with taxpayer funding and not DEF utility customer funding.

Q. How do you recommend that the Commission treat the proposed subsidies to UF by DEF customers?

A. The Commission should disapprove of any customer-funded spending on the UF boilers and the steam subsidy unless and until it demonstrates the cost-effectiveness of the spending to DEF's customers in an objective, comprehensive, and transparent BCA.

X. DEF PROPOSES ADDITIONAL UNJUSTIFIED AND UNREASONABLE SPENDING THAT THE COMMISSION SHOULD DENY IN THIS PROCEEDING

Q. What other DEF spending proposals merit the Commission's review and disapproval?

A. DEF proposes new spending of about $3.325 billion over the period 2025-2027, with all but $280 million of this on transmission and distribution projects.[55] With the single exception of its assertions regarding the Powerline battery energy storage project, DEF has not performed transparent, comprehensive BCAs or fairly evaluated alternatives to any of this spending.[56] The Commission should act to reign in DEF's proposed spending spree in order to help ensure customers can afford essential electric service. I point out several issues where Commission action is appropriate, though my silence on any particular issue should not be considered support for any DEF proposal. The issues that I propose to call the Commission's attention include the following:

- The Commission should deny any rate recovery of employee incentive compensation costs until DEF submits a revised employee incentive compensation plan.[57] The Commission should require DEF to submit a plan that includes shareholder direct "below the line" funding of at least 50% of the program budget and that reflects two major changes: (1) An essential performance metric that addresses maintaining and improving customer affordability, especially among residential customer with income levels at or below 400% of the Federal poverty level. In particular, this metric should be addressed with permanent or long-lived actions that do not merely require other customers to pay low-income customer bills. (2) The revision of any earnings-based performance metrics to ensure that only earnings improvements that reflect measurable customer benefits qualify for inclusion in any incentive compensation program.
- The Commission should disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether DEF spending proposals will result in rates that are fair, just,

and reasonable.

- The Commission should disapprove any further expansion of the Clean Energy Connection program unless and until DEF redesigns the program to eliminate interclass cross-subsidies and a cost structure that requires non-subscribers to bear the program cost risks associated with forecasted costs and savings.
- The Commission should disapprove any spending by DEF under the Vision Florida unless and until DEF demonstrates the merits of such investments through objective, comprehensive, and transparent BCAs that evaluate proposed investments against all reasonable alternatives.
- The Commission should disapprove most, if not all, of the rate recovery for the transmission and distribution growth, expansion, and major project proposed spending as unjustified and excessive in the absence of objective, comprehensive, and transparent BCAs that evaluate proposed investments against all reasonable alternatives.

XI. CONCLUSIONS AND RECOMMENDATIONS

Q. What do you conclude from your review of DEF's application in this proceeding?

A. DEF's proposed spending is excessive and a threat to electric service affordability, especially for low- and moderate-income Floridians. DEF's specific proposals are almost entirely unsupported by benefit-cost analysis or consideration of alternatives, and are unjustified against load and customer growth in its service territory. Now is the time for the Commission to require DEF to behave in a more responsible manner—as the utility would if it faced competition.

Q. What are your recommendations to the Commission?

A. In this testimony, I present a number of recommendations designed to reduce the outsized electric bills and energy burdens faced by DEF's residential customers. These recommendations include:

(1) Ending use of the residential minimum bill and replacing it with a customer charge based on basic customer cost;

(2) Reducing DEF's ROE to 9.50%;

(3) Disallowing use of the proposed method for cost allocation and substitute a 12 CP and 50% AD cost allocation, without using the principal of "gradualism" to shift additional costs onto residential customers;

(4) Eliminating growth, expansion, and major project spending for transmission and distribution unless and until a BCA is completed;

(5) Eliminating spending for Vision Florida projects unless and until a BCA is completed;

(6) Requiring DEF to produce BCAs to support all requests for capital spending projects for $1 million or more.

Q. Does this conclude your testimony?

A. Yes, it does.

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[1] DEF Petition for Rate Increase (Apr. 2, 2024) at 6, ¶ 13.
[2] *Id.* at 8–10, ¶¶ 19–22.
[3] *Id.* at 11–12, ¶ 27.
[4] *Id.* at 5, ¶ 10.
[5] DEF witness Benjamin Borsch direct testimony ("Borsch Direct"), Exh. BMHB-2 at 2.
[6] *Id.* at 1.
[7] *Id.* at 3.
[8] DEF Resp. to OPC INT 55.
[9] DEF Resp. to FL Rising/LULAC INT 11.
[10] DEF Resp. to FL Rising/LULAC INT 9.
[11] U.S. Energy Info. Admin., EIA-861 M Sales and Revenue Data (2023), https://www.eia.gov/electricity/data/eia861m/archive/xls/sales_ult_cust_2023.xlsx.
[12] DEF Resp. to OPC POD 1-7.
[13] *Id.*
[14] *See* U.S. Energy Info. Admin., EIA 2020 RECS Survey Data, Tables CE1.1-1.5, https://www.eia.gov/consumption/residential/data/2020/index.php?view=consumption.
[15] Diana Hernández, *Understanding Energy Insecurity and Why It Matters to Health,* 167 Soc. Sci. Med. 1, 2 (Oct. 2016), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5114037/.
[16] *Id.* .
[17] U.S. Dept. of Energy, *Low-Income Energy Affordability Data Tool,* Office of Energy Efficiency and Renewable Energy, https://www.energy.gov/scep/slsc/lead-tool (last visted June 5, 2024).
[18] Federal Poverty Level data, which applies to Florida, is available from the U.S. Department of Health and Human Services. For 2020 levels, see https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines/prior-hhs-poverty-guidelines-federal-register-references/2020-poverty-guidelines. For 2024 levels, see https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines.
[19] Fla. Dept. of Heath, *Individuals below Poverty Level (Census ACS),* https://www.flhealthcharts.gov/ChartsDashboards/rdPage.aspx?rdReport=NonVitalInd.Dataviewer&cid=294 (last visted June 5, 2024).
[20] DEF Resp. to FL Rising/LULAC INT 3-73.
[21] "E-6b Unit Costs, Proposed Rates" submitted in Resp. to OPC POD 1-7.
[22] "E-6a Unit Costs, Present Rates" submitted in Resp. to OPC POD 1-7.
[23] DEF Resp. to FL Rising/LULAC INT 1-3.
[24] DEF Resp. to FL Rising/LULAC INT 1-22.
[25] DEF underperforms in energy efficiency as against both U.S. and Southeast utility averages. *See* Forest Bradley-Wright, Southern Alliance for Clean Energy, *Energy Efficiency in the Southeast, 5th Annual Report* at 7 (2023) https://cleanenergy.org/wp-content/uploads/Energy-Efficiency-in-the-Southeast-Fifth-Annual-Report.pdf.
[26] *See* DEF Resp. to FL Rising/LULAC INT 1-22.
[27] *Id.*

[28] James C. Bonbright, Principles of Public Utility Rates at 347 (1961), https://www.raponline.org/wp-content/uploads/2023/09/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.
[29] Jim Lazar & Wilson Gonzalez, Smart Rate Design for a Smart Future at 6, 36, Regulatory Assistance Project (July 2015), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.
[30] Bonbright, *supra* n.27 at 347.
[31] "E-6b Unit Costs, Proposed Rates" submitted in Resp. to OPC POD 1-7.
[32] Jim Lazar, Paul Chernick, & William Marcus, Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project (Jan. 2020), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.
[33] DEF Petition for Rate Increase at 9–10, ¶ 22.
[34] *Id.*
[35] DEF witness Adrien McKenzie direct testimony ("McKenzie Direct").
[36] McKenzie Direct at 42, et seq.
[37] *Id.* at 10.
[38] Edison Electric Inst. ("EEI"), *Electric Company Industry Financial Data and Analysis – Rate Review Data* (2023 Q4), https://www.eei.org/issues-and-policy/finance-and-tax.
[39] *Id.*
[40] Christopher Rugaber, *Fed Powell Suggests Taming Inflation Will Take Longer Than Expected*, PBS NewsHour (May 1, 2024), https://www.pbs.org/newshour/economy/watch-live-fed-chair-powell-holds-news-conference-following-interest-rate-meeting.
[41] Even after building new solar facilities proposed in this application, DEF will still rely on fossil fuels for more than 80% of its generation. Seixas Direct at 17.
[42] DEF Resp. to FL Rising/LULAC INT 40, 46.
[43] Calculated by modifying common equity ROE within DEF updated jurisdictional separation study and cost of service study. 8- JSS COS (12 CP & 25 AD) 2025 Updated Fall 2023 Sales Forecast.
[44] Olivier Direct at 36-37.
[45] The Wikipedia entry related to the so-called "Ramsey Problem" explains this approach as follows: "The Ramsey problem, or Ramsey pricing, or Ramsey–Boiteux pricing, is a second-best policy problem concerning what prices a public monopoly should charge for the various products it sells in order to maximize social welfare (the sum of producer and consumer surplus) while earning enough revenue to cover its fixed costs. Under Ramsey pricing, the price markup over marginal cost is inverse to the price elasticity of demand and the price elasticity of supply: the more elastic the product's demand or supply, the smaller the markup." Wikipedia, *Ramsey Problem*, https://en.wikipedia.org/wiki/Ramsey_problem (last visted June 5, 2024).
[46] DEF Resp. to FL Rising/LULAC ROG 12
[47] Olivier Direct at 20–21.
[48] *Id.* at Exh. MJO-5.
[49] *Id.*
[50] DEF Resp. to FL Rising/LULAC INT 1.

[51] *See supra* Table KRR-3: DEF Current and Project Peak Reserve Margins.
[52] DEF Resp. to FL Rising/LULAC INT 2.
[53] *Id.*
[54] *Id.*
[55] DEF Resp. to FL Rising/LULAC ROG 15.
[56] DEF Resp. to FL Rising/LULAC ROG 10.
[57] DEF's incentive compensation programs are detailed in DEF Resp. to OPC INT 11-316, which is inexplicably designated confidential in its entirety.

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(Whereupon, prefiled direct testimony of Tony Georgis was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	)))	**DOCKET NO. 20240025-EI**

DIRECT TESTIMONY OF TONY GEORGIS

ON BEHALF OF WHITE SPRINGS AGRICULTURAL CHEMICALS, INC. D/B/A PCS PHOSPHATE – WHITE SPRINGS AND NUCOR STEEL FLORIDA, INC.

JUNE 11, 2024

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Tony M. Georgis. I am the Managing Director of the Energy Practice of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Boulevard, Suite 450, Lakewood, Colorado 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of White Springs Agricultural Chemicals, Inc. doing business as PCS-Phosphate – White Springs and Nucor Steel Florida, Inc.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I have a Master of Business Administration degree from Texas A&M University with a specialization in finance. Also, I earned a Bachelor of Science in Mechanical Engineering from Texas A&M University. In addition to my undergraduate and graduate degrees, I am a registered Professional Engineer in the states of Colorado and Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I am the Managing Director of NewGen's Energy Practice. I have more than 25 years of experience in engineering and economic analyses for the energy, water, and waste resources industries. My work includes various assignments for private industry, local

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governments, and utilities, including sustainability strategy, strategic planning, financial and economic analyses, cost of service and rate studies, energy efficiency, and market research. I have been extensively involved in the development of unbundled cost of service ("COS") and pricing models during my career. A summary of my qualifications is provided within Exhibit TMG-1 to this testimony.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony to the California Public Utilities Commission, the Public Utility Commission of Texas, the Florida Public Service Commission ("Commission"), and the Indiana Utility Regulatory Commission, as shown in my resume and record of testimony included as Exhibit TMG-1.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. <u>SUMMARY AND RECOMMENDATIONS</u>

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR DIRECT TESTIMONY?

A. My testimony addresses several issues and concerns regarding cost of service, revenue allocation and rate design that are presented in the Duke Energy Florida, LLC ("Duke" or "DEF") April 2, 2024 petition to increase its base rates. The base rate revenue increases proposed amount to more than 20% in 2025 from current base rates, with subsequent increases of 2.75% and 3.6% in 2026 and 2027, respectively.[1] In total, DEF

[1] *See* DEF Exhibit MJC-2, Company-Proposed Allocation of the Target Revenue and Rate Increase/(Decrease) by Rate Class.

seeks to increase its base rates over this period by roughly $820 million (28%) over current base rates, with the cumulative increase in DEF revenues exceeding $2 billion.[2] While the DEF proposed system average rate increase is more than 20%, DEF proposes even larger increases to its commercial and industrial service classes, plus DEF proposes to slash the interruptible service credit by more than 40%.[3] The net result for customers on the interruptible service rates is a base rate increase in 2025 in excess of 50%.[4]

My testimony explains that DEF's cost of service study systematically over-allocates utility production and transmission costs to its non-firm interruptible service commercial and industrial customers. I address other errors and issues in the Duke Energy cost of service analysis. Finally, I explain that DEF's proposed reductions in the interruptible and curtailable service credits are not warranted. Specifically, my testimony explains:

- How DEF production and transmission costs should be allocated to DEF's non-firm loads for cost of service ("COS") purposes;
- The system benefits, importance, and value of DEF's interruptible service and why the Commission should reject the proposal to substantially reduce the prevailing credits;

[2] *Id.*

[3] *See* DEF MFR Schedule A-3, p. 21 of 24.

[4] *See id.*

- Why DEF's reliance on the 12 month coincident peak ("CP") and 25% average demand ("AD") method for allocating production costs in its cost of service analysis is misplaced;
- Why a four month CP method is more appropriate for allocating DEF production costs;
- Why a correction is required to DEF's allocation of the production tax credits ("PTC") related to the production of solar photovoltaic energy; and
- Why DEF's distribution costs should be allocated using a Minimum Distribution System ("MDS") approach.

Each of these adjustments to DEF's allocated cost of service study aim to correct systematic over-allocation of its embedded costs to large customers, and particularly the curtailable service ("CS") and interruptible service ("IS") customer classes. Overall, I conclude that, due to these material errors, DEF's COS results cannot be relied upon for imposing above system average increases on the general service demand, curtailable, and interruptible service classes. I accordingly recommend that any rate increases that the Commission approves for DEF be assigned among rate classes on an equal percentage basis tied to the approved system average increase. Finally, I demonstrate that an increase to the CS and IS credits is justified rather than the substantial decrease that DEF proposes in this case.

III. <u>CURTAILABLE AND INTERRUPTIBLE SERVICE BACKGROUND AND DUKE'S VALUE MISALIGNMENT</u>

Q. PLEASE DESCRIBE DUKE'S CURRENT CS AND IS PROGRAMS.

A. The CS and IS service programs are important and long-standing DEF demand response programs. They are electric system reliability programs, which means that for IS service, DEF can interrupt service to all of a participating customer's load any time there is a system emergency that threatens service to Duke's firm service customers.[5] The DEF CS and IS programs have been in place for decades and have benefited Duke and its firm service customers by helping the utility avoid or defer the construction of generation peaking units during that time.

IS customers must provide interruptible capacity with no limit on the number of interruptions initiated by Duke. These interruptions may occur with little or no effective warning and will last as long as DEF requires to ensure continued reliable service to its firm retail loads.[6] DEF has designed the IS tariff to ensure that it can count on the committed load reduction in its resource planning. IS customers must commit for five-year contractual periods and must give three years of advanced notice to exit the program. CS service contains the same requirements as IS with the exception of two-year contract commitments instead of five years. However, if the CS customer transfers from a curtailable to a firm service offering, they must provide at least 36

[5] *See* DEF MFR Schedule E-14, Rate Schedule IST-2, DEF Tariff Section No. VI, Thirtieth Revised Sheet No. 6.265.

[6] *Id.*

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months prior written notice to Duke, which effectively makes the CS commitment three years, not two. Integration of the CS and IS capacity in DEF's resource planning is documented in its Ten-Year Site Plan.[7]

It is important to note that DEF interruptions of IS participants are not limited under the tariff to the system peak hours, but could occur at any time that there is a system need.[8] This form of non-firm service constitutes a virtual peaking or black-start generation unit that could be quickly dispatched at any time period, including baseload or critical system peaking events. Duke controls the customer's electric disconnect switches; thus, the load reduction is effectively 100% reliable and available. CS service interruptions function nearly identically to the IS service except that the customer controls their load reduction when called by DEF.[9]

Q. PLEASE PROVIDE SOME BACKGROUND ON INDUSTRY PRACTICES FOR COST OF SERVICE AND ALIGNING COST ALLOCATION WITH COST CAUSATION.

A. The core principle in performing a fully allocated COS study and in designing rates is to align cost recovery with cost causation. On any electric system, different customer classes and consumption behaviors impose varying costs on the system. For example, a large manufacturing facility that takes service at high voltage does not use the local

[7] *See* Exhibit TMG-6, Duke Energy Florida, LLC's 2024 Ten-Year Site Plan, at p. 33 of 135 (Schedule 3.1.1).

[8] DEF MFR Schedule E-14, Rate Schedule IS-2, DEF Tariff Section No. VI, Thirty-First Revised Sheet No. 6.255.

[9] *See, e.g.*, *id.*, Rate Schedule CS-2, DEF Tariff Section No. VI, Fourth Revised Sheet No. 6.237.

distribution network. Thus, distribution costs should not be allocated to, nor recovered from, those customers or customer class.

Q. WHAT TYPES OF PRODUCTION-RELATED COSTS DOES DUKE INCUR TO PROVIDE PRODUCTION SERVICE?

A. Duke incurs both demand and energy related costs to provide production services to retail customers. Demand costs are fixed costs related to constructing power generation facilities while energy costs vary with the amount of energy consumed. These variable or energy costs include items such as natural gas or fuel purchases to run generation plants.

Q. **HOW DOES DUKE ALLOCATE PRODUCTION AND TRANSMISSION DEMAND COSTS TO CUSTOMER-RELATED CLASSES?**

A. Duke allocates demand costs associated with production and transmission plant to all customer classes based on their metered demand coincident with the 12 monthly peaks on the Duke system.[10] All of a customer class's metered load is considered firm load even when a customer class does not receive firm service.[11] Duke witness Marcia Olivier explains that DEF's cost of service analysis:

> is based on the premise that all the [rate] groups' load requirements are firm. This is because the Company's various forms of non-firm service are elements of its demand side management ("DSM") program, and, therefore, the value of each rate group's load subject to interruption or curtailment is not a consideration in setting base rates….[12]

10 Direct Testimony of Marcia J. Olivier on behalf of Duke Energy Florida, LLC at p. 33 (DEF witness Olivier Testimony).

11 *Id.* at pp. 40-41.

12 *Id*.

Q. WHAT ALLOCATORS DOES DUKE USE TO ALLOCATE ALL PRODUCTION RELATED COSTS?

A. DEF witness Olivier explains that the utility relies on the 12CP (12 monthly peaks) and 25% average demand ("25AD") approach (collectively, the "12CP and 25AD" method) to allocate all production demand related costs, including those listed above. DEF bases its proposed allocation of revenue increases for each of the three test years on the cost of service results produced using the 12CP and 25AD method.[13]

Q. HOW DOES DUKE DESIGN AND CONSTRUCT ITS GENERATION AND TRANSMISSION SYSTEMS?

A. For resource planning purposes, Duke designs and constructs its generation and transmission systems to meet expected net firm peak demands on the utility system plus a reserve margin. DEF witness Benjamin Borsch explains that DEF has two basic planning criteria: satisfying a minimum Reserve Margin and a maximum Loss of Load Probability, but that it effectively plans based on reserve margin.[14] Duke has not in the past, and does not currently, treat the full measured system coincident demand of CS and IS customers as firm loads that Duke must design generation resources to serve. As is shown in its Ten-Year Site Plan, DEF deducts the CS and IS demands from the determination of Net Firm Demand upon which Duke calculates its capacity reserve margins and generation capacity requirements.[15] Hence, DEF does not build or acquire capacity to serve non-firm load.

[13] *See id.* at pp. 35 & 40.

[14] Deposition of Duke Energy Florida, LLC witness Benjamin Borsch at p. 17 ("[W]e have found historically that planning to the 20% reserve margin gives you a portfolio which also satisfies the LOLP criteria.").

[15] Exhibit TMG-6 at page 33 of 135 (Schedule 3.1.1).

In its 2024 Revised Ten-Year Site Plan, DEF calculates 402 MWs of available interruptible load reductions that it subtracts from the Net Firm Demand requirements for 2024.[16] Adding a 20% reserve margin to that amount yields 482 MWs of current CS and IS generation resource benefit.[17] Similarly, Duke constructs its transmission system to serve its firm service peaking requirements on the system.[18]

Q. IS DUKE'S ALLOCATION OF PRODUCTION COSTS IN ITS COST OF SERVICE STUDY CONSISTENT WITH THE WAY IT DESIGNS AND CONSTRUCTS ITS GENERATION SYSTEM?

A. No. As Duke witness Olivier states, for its cost of service purposes, DEF considers all rate groups to be firm load.[19] As CS and IS receive a lower level of service than firm retail service, this constitutes a fundamental error in Duke's COS that mismatches cost assignment and cost causation. By allocating its production costs based on customer

[16] *Id.*

[17] 402MW x 20% reserve = 80MW of avoided reserves; 80MW + 402MW = 482MW.

[18] Direct Testimony of Edward L. Scott on behalf of Duke Energy Florida, LLC at pp. 19-20 ("[A]pproximately two-thirds of DEF's transmission capital expenditure requirements for 2025-2027 are allocated to the Growth category. Growth and system expansion include new service accounts, new major construction projects, and increased electrical demand in an area, all of which affect planning and operations on the transmission system.").

[19] DEF witness Olivier testimony at p. 40.

class metered demand, and not an amount reduced for interruptible capacity, Duke over-allocates costs to the CS and IS customer classes.

Q. DOES DEF INCORPORATE ANY CORRESPONDING ADJUSTMENT IN THE DEMAND ALLOCATORS IN ITS COS STUDY TO ACCOUNT FOR THIS MISALIGNMENT?

A. No, there is no adjustment in the COS. To ensure cost allocation is aligned with cost causation, Duke should adjust the customer class demand allocations to account for non-firm demand. By failing to do so, DEF's cost study systematically over-allocates production and transmission costs to Duke's non-firm, interruptible customer classes. Furthermore, National Association of Regulatory Utility Commissioners' ("NARUC") Electric Utility Cost Allocation Manual provides instructions how non-firm load is treated in COS studies by noting that non-firm customers are usually excluded from the demand allocation factor calculations in recognition of their level of service. [20] This lack of an adjustment unnecessarily depresses the reported CS and IS class returns reported in the COS results, which in turns leads to DEF's proposal to assign a higher than system average revenue increase to these non-firm customer classes.

Q. SHOULD DUKE MAKE ANY ADJUSTMENT TO THE COST OF SERVICE OR DEMAND ALLOCATORS TO MAINTAIN CONSISTENCY IN COST CAUSATION PRINCIPLES AND COS FUNDAMENTALS?

A. Yes. As Duke chose to allocate production and transmission costs under the assumption that all customer classes are firm load, to ensure consistency with cost

[20] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at p. 76 (1992), *available at* https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD (NARUC Cost Allocation Manual).

causation principles, CS and IS credits should be incorporated in the COS based on embedded production and transmission costs. This adjustment would correct the COS for how Duke chose to allocate the production and transmission costs to CS and IS customers. This approach will produce an accurate COS result and cost causation approach in quantifying the benefits as well as the costs imposed on the DEF system by the CS and IS classes.

Q. HOW DOES DUKE EXPLAIN THE INCONSISTENCY IN ITS COST OF SERVICE STUDY?

A. Duke witness Olivier maintains that credits provided to non-firm loads through its demand side management programs corrects for the cost misallocation.[21]

Q. DO YOU AGREE?

A. No. The CS and IS credits contained in DEF's DSM plans do not take the on-going and embedded cost benefits of its existing program participants into account at all. Docket No. 20240013-EG, *In re: Commission review of numeric conservation goals (Duke Energy Florida, LLC)*, looks only to incremental participation based on assumed future marginal (avoided) costs. The COS study, however, examines actual embedded costs for a historic period (in this case the year 2023) adjusted for future Test Year forecast changes to those embedded costs (2025, 2026, and 2027). To maintain consistency in benefits and cost causation, the required adjustment to the COS allocations must look to the embedded cost benefits of the non-firm service, which I describe and quantify below, and not marginal benefits or costs.

[21] DEF witness Olivier testimony at pp. 40-41.

Q. PLEASE EXPLAIN.

A. Embedded costs evaluated in the Duke COS study represent the accumulated historical and planned costs for Duke's generation and transmission system. Historically, Duke has not designed its system or constructed production assets to serve CS and IS customer interruptible loads, and thus the embedded costs are lower than they otherwise would be. Thus, there is an on-going CS and IS benefit (or reduction in costs) reflected in DEF's embedded costs but not in the COS for each customer class. This mismatch leads to over-allocation of costs to CS and IS customers.

Q. WHAT ARE THE EMBEDDED COST BENEFITS ATTRIBUTABLE TO CS AND IS SERVICE?

A. Instead of looking at a projected marginal unit at an assumed cost, the embedded cost benefits must consider historic and Test Year generation and transmission costs commensurate with 402 MWs of assured load reduction, plus an additional reserve margin. Exhibit TMG-2 details the system-level total costs for generation and transmission services and translates those total costs to unit costs (i.e., per kW) based on the Duke system coincident peak billing determinants. I used Duke's coincident peak demand billing units to reflect the unit cost values during peak demand periods on the system because that best aligns with how the CS and IS services are quantified and used by Duke in its Ten-Year Site Plan and generation resource plan (even though DEF has the ability to interrupt CS and IS loads whenever they are needed).

As shown in Exhibit TMG-2, based on Duke's Updated Fall of 2023 sales forecast and related cost of service MFRs, without any other adjustments, generation unit costs, based on the coincident peaks, are $15.36 per kW, and the transmission costs are $6.18 per kW for the 2025 Test Year. Thus, the total unit cost for generation and transmission for the Duke system based on coincident peak demands is $21.54 per kW. When the 20% reserve margin is applied to this total it becomes $25.84 per kW.[22] This amount fully reflects Duke's embedded cost of firm capacity and the on-going value to the system of the existing CS and IS interruptible load.

Q. HOW SHOULD THE EMBEDDED CS AND IS COST BENEFIT BE APPLIED IN THE COST OF SERVICE STUDY?

A. The short answer is that the COS study should be revised to develop distinct production and transmission demand allocation factors for firm and non-firm service. The COS should allocate production and transmission costs based on the actual firm service delivered and reduced for the CS and IS interruptible capacity. This would rectify the over-allocation of production and transmission costs to the CS and IS classes discussed previously. The alternative to revamping the cost study altogether is to calculate an allocation adjustment based on the above-noted embedded benefits attributable to existing CS and IS load participation to appropriately reduce the production and transmission costs allocated to these classes.

Q. HOW DOES DUKE'S PROPOSED CS AND IS CREDIT COMPARE TO THE EMBEDDED COST VALUE REALIZED IN THE COS?

A. DEF proposes a going-forward IS credit of $4.62 per kW.[23] As shown above, existing IS loads currently provide a fully realized, embedded cost-based benefit to DEF of

[22] *See* Exhibit TMG-2 at p. 1 of 1.

[23] *See, e.g.*, MFR Schedule E-14, Rate Schedule IS-2, DEF Tariff Section No. VI, Thirty-First Revised Sheet No. 6.255.

$25.84 per kW. That is a difference of more than $20 per kW that is missing from DEF's approach.

IV. OTHER PROPOSED CORRECTIONS TO DUKE'S COST OF SERVICE

Q. WHAT ERRORS OR ISSUES DID YOU IDENTIFY IN DUKE'S COS MODEL AND THE MINIMUM FILING REQUIREMENTS ("MFR")?

A. In addition to the error and misalignment of the value for CS and IS interruptible capacity, I have identified issues and errors related to the production and transmission demand cost allocation method, the production tax credit ("PTC") allocation, and the allocation method for distribution costs.

A. Production and Transmission Demand Cost Allocation

Q. HOW DOES DUKE ALLOCATE PRODUCTION AND TRANSMISSION DEMAND COSTS TO THE CUSTOMER CLASSES?

A. As stated previously in my testimony, Duke allocates production demand revenue requirement to the customer classes using the 12CP and 25AD method.[24] Transmission demand costs are allocated on a 12CP methodology.[25]

Q. ARE DEF'S ASSUMPTIONS FOR ALLOCATING PRODUCTION DEMAND COSTS TO CUSTOMER CLASSES REASONABLE?

A. No. The 12CP and 25AD allocation approach is not appropriate for how DEF's system is planned and operates and is inconsistent with its resource planning criteria and basic

[24] DEF witness Olivier testimony at p. 34.

[25] *Id.*

cost causation principles. Based on the system data provided for the Base Rate Case and used for COS allocators, Duke's system is a summer peaking system with the four highest peaks in June, July, August, and September.[26] These peaks drive Duke's required reserve margin for planning purposes and are materially higher than either DEF's average demands or peaks in other months.

Q. PLEASE FURTHER DESCRIBE DUKE'S SYSTEM PEAK DEMANDS AND RELATED CHARACTERISTICS.

A. The DEF system is more variable than the two other large investor owned utilities in Florida, Florida Power & Light Company ("FPL") and Tampa Electric Company ("TECO"). This variability is seen in Duke's system as it operates at a comparatively lower load factor, which means it has a greater disparity between its peak and average demands compared to FPL and TECO.[27] In practical terms, the lower DEF system load factor means that it is more reliant on peaking generation to follow load and meet less frequent peak demands than the other two large investor-owned utilities.

[26] *See* DEF MFR Schedules E-9 & E-17.

[27] *Cf.* Exhibit TMG-6 at p. 39 of 135 (Schedule 3.3.1, History and Forecast of Annual Net Energy for Load (GWh)) (showing a load factor between 2014 and 2023 ranging between 48.9% and 53.1%); Florida Power & Light Company Ten Year Power Plan Site Plan 2024-2033 at Schedule 3.3, History of Annual Net Energy for Load (GWh), *available at* https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2024/Florida%20Power%20and%20Light%20Company.pdf (showing a load factor between 2014 and 2023 ranging between 57.7% and 60.9%); Tampa Electric Company 2024 Ten-Year Site Plan at Schedule 3.3, History and Forecast of Annual Net Energy for Load (GWh), *available at* https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2024/Tampa%20Electric%20Company%20-%20Revised.pdf (showing a load factor between 2014 and 2023 ranging between 53.2% and 58.1%).

Q. PLEASE GENERALLY DESCRIBE DUKE'S NEAR TERM GENERATION RESOURCE PLANS AND CONTRIBUTIONS TO SYSTEM PEAKING NEEDS.

A. Between 2024 and the Test Year ending December 2027, Duke's current generation resource program is centered on retiring 705 MWs of oil-fired combustion turbines that collectively carry a summer capacity rating of 460 MWs.[28] Aligned with this large peaking capacity retirement, Duke plans on adding more than a dozen large scale solar projects amounting to 1,348 MWs of added nameplate generating capacity.[29] These solar additions offer only 434 MWs of what DEF considers to be firm summer capability.[30] Duke expects that the solar summer capability (both existing and new) will drop to less than 25% of nameplate rating by 2027 as the summer peak time moves later in the day.[31] In winter months, Duke deems the added solar capacity to have zero peak capability or contribution. [32]

Q. PLEASE EXPLAIN YOUR RECOMMENDED APPROACH FOR ALLOCATING DEF'S PRODUCTION COSTS.

A. Considering the operating characteristics of Duke's system, it is apparent that Duke may be electing to add significant amounts of solar generation to its system, but the utility's need is mostly for fast ramping and peak load following generation. Moreover,

28 *See* Exhibit TMG-6 at pp. 75-76 of 135 (Schedule 8).

29 *Id.*

30 *Id.*

31 *Id.* at p. 68 of 135 ("DEF recognizes that as solar penetration increases, including both DEF and customer owned PV, the relationship between the solar production and the coincident load peak will change. . . . DEF modeling derives an equivalent summer non-coincident, but on-peak-hour capacity value equal to 25% of the facility's nameplate rating for planned PV installations from 2025 to 2027 and 10% for 2028 and beyond.").

32 *Id.* at p. 16 of 135 (Schedule 1).

that need becomes increasingly more pronounced as DEF adds more intermittent, weather-sensitive solar power to its portfolio. Growth in sales will further drive the peak, while solar generation's contribution to the overall system will further erode the system load factor and lead to additional variability and increased ramping needs. This expected trendline requires a more realistic allocation of production costs based on peak demands.

Duke's monthly system peak demands suggest that allocating production costs based on the pronounced summer peak (4CP) would be most appropriate at this time as a reasonable transition from its historic 12CP and 1/13AD method and proposed 12CP and 25AD. Duke customers' contributions to these four monthly peaks more properly reflect the costs imposed on the system, as they drive the capacity investments to serve customers' firm loads. Furthermore, these months are all within 97% of the system peak in June.[33]

Q. PLEASE EXPLAIN YOUR RECOMMENDED APPROACH FOR ALLOCATING DEF'S TRANSMISSION DEMAND COSTS.

A. Transmission systems are constructed to serve the system loads, and the criteria to construct and operate the system are similar to that of the production function. As the transmission system is constructed to serve peaks, the transmission demand cost allocation should align with the production demand cost allocation. Furthermore, the NARUC cost allocation manual recommends aligning transmission and production

[33] *See* DEF MFR Schedules E-9 & E-17.

cost allocation as the transmission system is essentially an extension of the production system.[34] Thus, Duke should apply a 4CP allocation to the transmission demand costs.

Q. WHAT IS THE RESULT OF THE CLASS ALLOCATION AFTER APPLYING THE 4CP ALLOCATION METHOD TO DUKE'S PRODUCTION AND TRANSMISSION DEMAND COSTS?

A. Table 1 below summarizes the impact of adjusting the production and transmission demand cost allocations.

Table 1
Production and Transmission Demand Allocation Corrections

Customer Class	Proposed COS ($000)	Corrected COS ($000)	Difference ($000)
Total Retail Adjusted	$3,373,238.76	$3,373,238.76	$-
Residential	$2,155,768.04	$2,240,733.47	$84,965.43
Gen Service Non Demand	$193,589.97	$186,777.32	$(6,812.65)
Gen Service 100% L.F.	$11,668.07	$10,913.59	$(754.48)
Gen Service Demand	$775,775.97	$711,445.53	$(64,330.44)
Gen Service Curtailable	$2,917.99	$2,693.54	$(224.45)
Gen Service Interruptible	$104,675.98	$91,736.37	$(12,939.62)
Lighting Energy	$20,295.93	$18,042.75	$(2,253.18)
Lighting Facilities	$103,604.38	$105,921.84	$2,317.47
EV Solution	$4,942.42	$4,974.36	$31.93

B. Production Tax Credit Allocation Error

Q. WHAT IS THE FEDERAL PRODUCTION TAX CREDIT ("PTC")?

A. The PTC is a per kWh federal tax credit to businesses for electricity generated by a qualified renewable energy resource. The PTC can vary based on the type of renewable

[34] NARUC Cost Allocation Manual at p. 75.

technology and other factors such as certain labor requirements and content of the facility manufactured domestically in the U.S.[35]

Q. HOW DOES DUKE ALLOCATE THE INCOME TAX CREDIT FROM THE PTC IN THE COS TO THE CUSTOMER CLASSES?

A. Duke allocates the PTC benefit to the customer classes based on the total accumulated depreciation of all plant included in its rate base calculations.[36]

Q. IS THAT CORRECT?

A. No. The PTC is an energy production (i.e., kWh) based income tax credit to businesses. It provides a varying credit per kWh of energy generated from accepted renewable energy generation resources such as Duke's construction of solar photovoltaic plants. This credit varies from $0.0055 to $0.0275 per kWh depending on certain project construction and labor requirements.[37] Accumulated depreciation is a balance sheet, asset related item that quantifies the reduction in the book value of Duke's assets. It is not related to how much energy (i.e., kWh) is generated by renewable energy generation assets. It is therefore inconsistent to allocate the PTC benefit based on accumulated depreciation of plant.

[35] U.S. Environmental Protection Agency, *Renewable Electricity Production Tax Credit Information*, https://www.epa.gov/lmop/renewable-electricity-production-tax-credit-information (last accessed June 11, 2024).

[36] *See, e.g.*, DEF MFR Schedule E-1, 12 CP and 25% AD Cost of Service Study for Test Year 2025. at p. 10 of 230 (Line Nos. 3 & 505).

[37] U.S. Department of Energy, *Federal Solar Tax Credits for Businesses*, https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses (last accessed June 11, 2024).

Q. HOW DO YOU RECOMMEND DUKE ALLOCATE THE INCOME TAX CREDIT FROM THE PTC IN THE COS TO THE CUSTOMER CLASSES?

A. Duke must change the PTC allocation from accumulated depreciation of assets by customer class to the energy generated at the source level to serve each class. Using the Production Energy – Solar allocator for the federal PTC properly allocates the tax credits to the customer classes using the energy generated at the source level to serve the classes. This aligns the benefits received by Duke in the energy PTC with the energy consumption of the customer classes.

Q. WHAT IMPACT DOES THIS HAVE?

A. I applied the production energy allocation factor to the PTC in Duke's COS model. Table 2 summarizes the impact on the class total COS by changing the PTC allocation and leaving all other components of the COS unchanged.

Table 2
PTC Allocation Correction

Customer Class	Proposed PTC Allocation ($000)	Corrected PTC Allocation ($000)	Difference ($000)
Total Retail Adjusted	$(64,562.86)	$(64,562.86)	$-
Residential	$(40,588.70)	$(34,801.29)	$5,787.41
Gen Service Non Demand	$(3,495.51)	$(3,528.75)	$(33.24)
Gen Service 100% L.F.	$(224.81)	$(334.68)	$(109.87)
Gen Service Demand	$(15,282.00)	$(21,164.95)	$(5,882.94)
Gen Service Curtailable	$(59.09)	$(103.65)	$(44.56)
Gen Service Interruptible	$(2,211.35)	$(4,097.30)	$(1,885.95)
Lighting Energy	$(352.00)	$(532.24)	$(180.24)
Lighting Facilities	$(2,317.47)	$-	$2,317.47
EV Solution	$(31.93)	$-	$31.93

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C. Minimum Distribution System Methodology and Application

Q. PLEASE DESCRIBE THE MINIMUM DISTRIBUTION SYSTEM ("MDS") METHODOLOGY.

A. Distribution costs are driven by the utility's requirement to connect customers to the system no matter where they are located within its service area and the demand requirements those customers place on the system. The MDS method classifies costs as either customer-related or demand-related based on the concept of a minimum system. A minimum system simply represents that infrastructure cost required to connect a customer to the grid without further consideration of the customer's demand and energy requirements. This involves determining the minimum size of pole, conductor, transformer, and service drops required to simply connect to a customer premises. Once the minimum sizes of each of the distribution system components is determined, the value of the MDS plant is determined. This MDS portion of the total distribution plant is classified as customer-related and allocated to customer classes based on the number of customers. The remaining portion of the distribution plant is classified as demand-related and allocated to customers based on non-coincident peak demand allocation factors.

For example, if the total distribution plant value was $500 million and the MDS study calculated that $100 million was related to the minimum system, then 20% of the distribution plant would be classified as customer-related and allocated accordingly. The remaining 80% would remain classified as demand-related and allocated accordingly. The use of MDS represents a fair classification of distribution costs to customers because it recognizes that the physical location of the customer is an important driver of costs, and these costs should be properly classified as customer-related.

Q. IS THE MDS METHODOLOGY FOR CLASSIFYING COSTS AN ACCEPTED INDUSTRY PRACTICE AND CLASSIFICATION METHODOLOGY?

A. Yes. NARUC recognizes and details the use and application of the MDS methodology.[38]

Q. WHY SHOULD THE MDS METHODOLOGY BE APPLIED AND INCLUDED IN THE DUKE COST OF SERVICE AND BASE RATE CASE?

A. The MDS more accurately reflects the costs incurred by the utility to simply connect a customer to the system regardless of its size or load factor compared to Duke's current methodology. It calculates the minimum distribution component sizes for poles, transformers, and conductors to simply connect a customer's meter to the distribution substations to receive power. These distribution assets and infrastructure are required if the customer's peak demand is 10 kW or 0 kW. As there is a certain level or amount of distribution assets and infrastructure required whether or not the customer is using any power, a portion of the distribution system costs should be classified as customer related. This customer portion of the distribution costs does not vary with the demand levels; rather, it varies with the number of customers. Thus, it should be classified as customer-related.

[38] NARUC Cost Allocation Manual at p. 90.

Q. SHOULD THE MDS METHODOLOGY BE APPLIED AND ADOPTED IN THIS RATE PROCEEDING?

A. Yes, it should be included in this and subsequent Duke rate proceedings. The MDS methodology should be included to better reflect the costs imposed on the system by each customer class. The MDS is a long-standing accepted methodology for classifying distribution costs as both customer and demand related. These costs are then allocated using customer and demand allocation factors to the customer classes.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS AND RECOMMENDATIONS CONCERNING DEF'S COST OF SERVICE AND PROPOSED REVENUE ALLOCATION?

A. Considering the magnitude of the base rate increases that DEF has proposed, it is crucial to allocate any approved rate increases properly. I have quantified the cost of service effects associated with adopting a 4CP production cost allocation method and correcting the PTC allocation, but I was not able to re-run DEF's cost of service model to correct for the over-allocation of production costs to its non-firm loads or for allocating distribution costs using the MDS approach. All of the above corrections adjust for systematic over-allocation of costs to Duke's large customers, and particularly those on non-firm rates. I conclude that these corrections are large enough that DEF cannot rely on its filed COS results to justify imposing rate increases of 150% of the system average increase on its large customers. I propose instead that any approved increases be implemented on an equal percentage basis for all customer classes. This would better allocate the rate increase among Dukes customer classes given the errors in Duke's cost of service and the uncertain impact of some of those errors. Additionally, I recommend that the Commission require Duke to file a cost of service study incorporating the changes I recommend in its next base rate proceeding.

V. INTERRUPTIBLE SERVICE CREDIT

Q. PLEASE EXPLAIN DEF'S PROPOSED CHANGES TO THE CURRENT CS AND IS CREDITS.

A. Duke does not propose any changes to how the CS and IS programs work that would make them less valuable to the network as a resource. Duke simply proposes to pay participants less for providing the same benefits. Duke proposes to reduce the IS incentive credit from $7.72 per kW-month to $4.62 per kW-month, a reduction of more than 40%. DEF proposes to reduce the current CS credit of $7.72/kW-month to $5.82/kW-month. [39]

Q. DO YOU AGREE WITH DUKE'S PROPOSAL TO REDUCE THE IS AND CS CREDITS?

A. No. The CS and IS credits should each be increased rather than reduced. As discussed above, the CS and IS programs have helped Duke to avoid or defer additional transmission and generation investments over the decades in which the programs have been in place and customers have been participating. This on-going benefit provided by CS and IS participants includes the contracted and dedicated capacity reductions of 402 MWs as previously noted plus the associated reduction in DEF's required reserve margin.

[39] *See* MFR Schedule E-14, Rate Schedule CST-2, DEF Tariff Section No. VI, Twenty-Ninth Revised Sheet No. 6.245.

Q. WHAT CS AND IS CREDIT DO YOU RECOMMEND BE ADOPTED?

A. I recommend a credit of $9.01 per kW per month for CS and IS customers. This credit is based on the estimated revenue requirement associated with more recent (e.g., the last ten years) generation constructed in Duke and other investor owned utilities territories in Florida. This represents the generation plant and costs that would have been built if the CS and IS customers were treated as firm customers over the last ten years. As Duke has had limited new generator construction during this ten year period, I also reviewed the other Florida investor owned utilities to gain a more accurate representation of generation costs DEF has avoided in the last ten years. This represents a balance between the full embedded costs DEF has avoided over multiple decades (almost $26 per kW) and evaluates a more recent period and the representative revenue requirement associated with those avoided generation plant investments.

Q. PLEASE EXPLAIN.

A. If the CS and IS customers were treated at firm customers in resource planning over the last ten years, DEF would have had more net firm load than it needed to plan to serve. Duke would have increased the amount of the generation required to meet firm load requirements and the planning reserve margin throughout that time. As shown in Exhibit TMG-5, I calculated the relationship between the current DEF functionalized production demand revenue requirement and historic initial installed plant costs and apply that relationship to costs of constructing new generation over the last ten years in Florida. This approximates the production revenue requirements avoided as a result of CS and IS loads' lower quality of service (by lowering the net firm load and system requirements) over the last ten years.

This aligns with the embedded cost value methodology previously discussed in my testimony as it looks at prior generation investments and revenues requirements. However, it evaluates a more recent period than the multiple decades the CS and IS customers have contributed to reducing DEF's embedded costs included in this COS study. Exhibit TMG-4 and TMG-5 summarize the development of this credit amount.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of Rose Anderson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Petition for Rate Increase by Duke Energy Florida, LLC	))	Docket No. 20240025-EI

Direct Testimony of

Rose Anderson

On Behalf of

Sierra Club

June 11, 2024

C36-3659

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RA-5: Duke Energy Florida's Response to Off. of Pub. Counsel ("OPC") POD 1-7 attach. "B-13 CWIP – REDACTED.xlsx"

RA-6: Benjamin Borsch Deposition Transcript (Excerpted)

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1. Introduction and Purpose of Testimony

Q Please state your name and occupation.

A My name is Rose Anderson. I am a Principal Associate at Synapse Energy Economics ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy issues including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I review planning assumptions and modeling in utility integrated resource plans ("IRPs"). I evaluate utility rate case requests and engage in stakeholder IRP processes. My focus is on the economics of thermal generators and on the development of utility portfolios that minimize cost and risk while providing customers with reliable service.

Before joining Synapse, I performed economic analysis at the Oregon Public Utility Commission and at McCullough Research, an energy economics consulting firm. In my role on the Oregon Public Utility Commission staff, I prepared testimony and comments with recommendations for commissioners on utility integrated resource plans, power cost proceedings, rate cases, tariff filings, and Requests for Proposals ("RFP").

I have experience running the EnCompass and Aurora utility planning models and reviewing modeling inputs and outputs from these and other utility models.

A copy of my current resume is attached as Exhibit RA-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Florida Public Service Commission?

A No. I have testified in proceedings at the Oregon Public Utility Commission and Nevada Public Utilities Commission.

Q What is the purpose of your testimony in this proceeding?

A I evaluate Duke Energy Florida's ("DEF" or "the Company") coal-fired Crystal River North power plant, which consists of Units 4 and 5. I analyze the reasonableness of Duke's proposed continued spending at Crystal River North Units 4 and 5 based on my analysis of the economics of continuing to operate those units. I outline the savings from early retirement and procurement of replacement resources as needed, and how early retirement avoids environmental compliance costs that those units would otherwise incur. I discuss methods of increasing customer savings and mitigating the impacts of accelerated depreciation at Crystal River North from an earlier retirement of the plant.

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Finally, I argue that the Company could create ratepayer benefits by performing a study of the winter capacity contribution of solar.

Q How is your testimony structured?

A Section 2 summarizes my findings and recommendations. In Section 3, I provide relevant background on Crystal River North. In Section 4, I outline DEF's requests in this rate case to continue to operate the plant on coal and include the associated costs in rates. In Section 5, I explain why retirement of Crystal River North earlier than 2034 is likely to benefit customers. In Section 6, I present my analysis on the projected economics of the Crystal River North plant over the next decade. In Section 7, I outline the risks of continuing to rely on the Crystal River North plant, including risks from fuel price volatility and fuel supply disruptions, and future environmental regulation risk. In Section 8, I discuss ways to avoid the potential adverse rate impacts of accelerated depreciation, and highlight that obtaining funding under the U.S. Department of Energy's ("DOE") Energy Infrastructure Reinvestment ("EIR") program could result in over a hundred million dollars in additional savings for customers. Finally, in Section 9, I argue that DEF should evaluate the winter capacity contribution of solar.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies upon the application, testimonies, and other materials filed by DEF in this rate case, the Company's 2023 Ten-Year Site Plan ("TYSP"), discovery responses received from DEF, and publicly available data.

2. Findings and Recommendations

Q Please summarize your findings.

A My primary finding are:

1. Retiring Crystal River North as soon as possible, but by 2030 at the latest, instead of its currently planned retirement date of 2034, will have substantial benefits for customers.

2. Retiring Crystal River North by 2030 and replacing it with solar energy and capacity contracts would reduce system costs, while also reducing the risks associated with fuel prices and environmental regulations.

3. I estimate that retiring Crystal River North in 2030, for example, could save customers approximately $155 million.

4. In this rate case, the Company is requesting significantly more operations and maintenance ("O&M") spending than has historically been necessary to operate the Crystal River North coal units.

5. The Company's resource planning would likely benefit from a more rigorous consideration of the ability of solar to contribute to resource adequacy, including during winter.

6. Funding the Crystal River North retirement and replacement through the U.S. DOE EIR loan program would potentially generate more than $123 million in *additional* savings for customers, resulting in a total customer benefit of $278 million.

Q Please summarize your recommendations.

A In my testimony, I offer the following recommendations:

1. I recommend that the Company commit to cease burning coal and retire Crystal River North by the end of 2030.

2. Because benefits from an U.S. DOE EIR loan could surpass one hundred million dollars, I recommend that the Commission direct DEF to submit an application for EIR financing before the program's application deadline. This application should include the retirement of Crystal River North by 2030 and replacement with renewable energy.

3. The Company should offer a reasonable justification for the increase in O&M for the Crystal River North coal units, or its revenue requirement should be revised downward to more closely match historical spending.

4. Given that DEF expects to soon have thousands of megawatts ("MW") of solar on its system, the Company should perform a study of the capacity contribution of solar, including during winter.

3. Background on Crystal River North

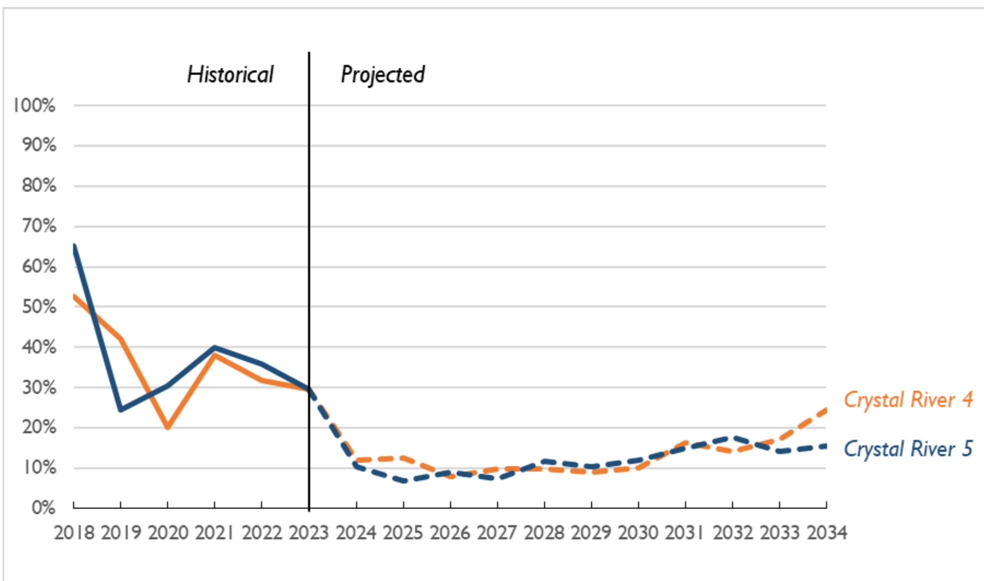
Q Please describe the current Crystal River North plant.

A Crystal River North consists of Crystal River Units 4 and 5, which are two coal-fired units located in Citrus County, Florida. Units 4 and 5 have capacities of approximately 739 MW each, for a combined total of approximately 1,478 MW. The plant is owned by DEF. Crystal River Units 4 and 5 were built in 1982 and 1984 and are 42 and 40 years old, respectively.

Q Please describe the recent historical and projected utilization of Crystal River North.

A As shown in Figure 1 below, the annual capacity factors at Crystal River Units 4 and 5 have ranged between 25 percent and 42 percent since 2019, and in the past few years have displayed a steadily decreasing trend.[1] The current capacity factors are around 30 percent. Over the next decade, DEF projects the units' utilization will continue to fall, and remain between 8 percent and 20 percent through 2033.[2]

Figure 1. Capacity Factors at Crystal River North Units 4 and 5



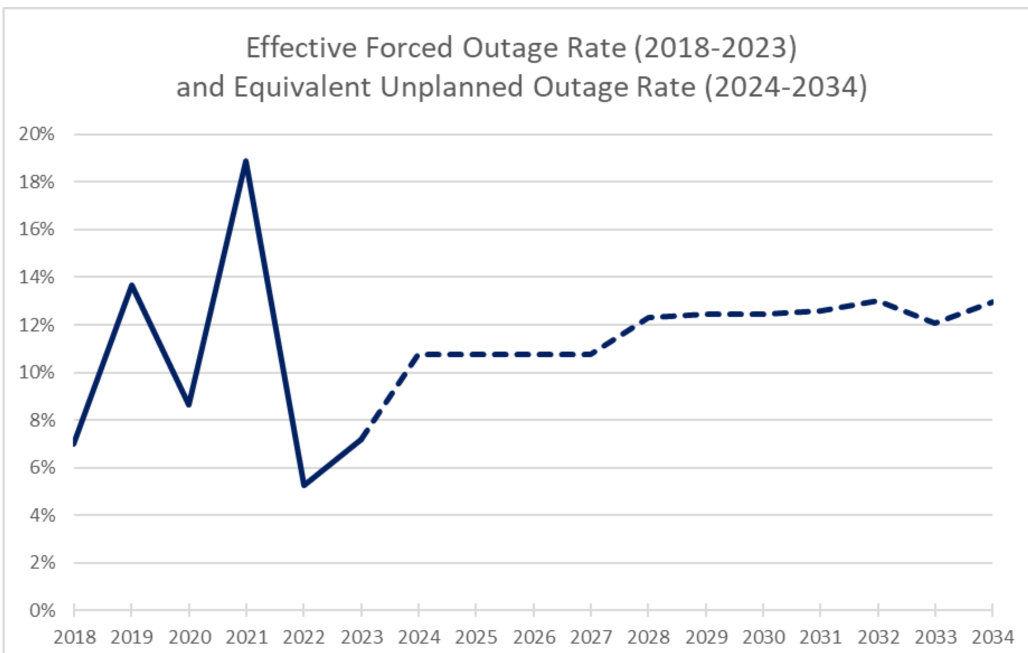
Source: EIA Form 923 and DEF Responses to SC ROG 1-7 (Ex. RA-2).

[1] Energy Information Agency. Form 923.
[2] DEF Response to SC ROG 1-7(d) (Ex. RA-2).

Q How reliable has Crystal River North been in recent years, and how reliable are the Units expected to be in the future?

A As shown in Figure 2 below, Crystal River North Units 4 and 5 have a combined effective forced outage rate that has ranged from about 5 percent to about 19 percent over the last five years.[3] This upper range is above the Company's projected future outage rates, which range between 11 and 13 percent over the next decade, with an increase in expected forced outages as the plant approaches retirement.[4]

Figure 2. Forced Outage Rate at Crystal River North



Source: DEF Responses to SC ROGs 1-6(i) and 1-7(g),(h) (Ex. RA-2).

[3] DEF Response to SC ROG 1-6(i) (Ex. RA-2).
[4] DEF Response to SC ROG 1-7(g), (h) (Ex. RA-2).

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Q What is the Company's plan for the retirement of Crystal River North?

A The Company's 2024 Ten-Year Site Plan states that Crystal River Units 4 and 5 will be retired in 2034.[5]

Q What analysis has the Company performed to support the 2034 retirement date?

A In 2020, DEF performed an economic analysis of Crystal River North retirement dates. The Company compared a 2042 retirement with 2034, 2029, and 2026 retirement dates for units at Crystal River North and evaluated replacement of the units with conventional generation and with solar and battery storage.[6] The 2020 study found that the 2034 retirement would reduce risks to customers associated with fuel price volatility and environmental regulation relative to a 2042 retirement, while allowing time for the construction of replacement resources.[7] Subsequently, the 2034 retirement date was included in the 2021 rate case settlement.[8] DEF acknowledges that it has not conducted any new retirement analysis since that 2020 study.[9] As explained in greater detail below, economic conditions and new environmental regulations have made the continued operation of Crystal River North coal units a riskier and costlier proposition for DEF's customers.

[5] DEF Ten-Year Site Plan at 3-49 (Apr. 2024) [hereinafter "DEF 2024 TYSP"] (Ex. RA-3).
[6] DEF Response to SC ROG 1-1 and 1-2. (Ex. RA-2); *see also* DEF Response to Sierra Club Request for Production of Documents ("SC POD") 1-4, attach. "CRN Presentation for 12152020", Bates Nos. 20240025-SIERRACLUBPOD1-00000066-105 (Ex. RA-4).
[7] DEF Response to SC ROG 1-1 and 1-2 (Ex. RA-2).
[8] DEF Response to SC ROG 1-1 (Ex. RA-2).
[9] DEF Response to SC ROG 1-1 (Ex. RA-2).

4. COMPANY REQUESTS FOR CRYSTAL RIVER NORTH IN THIS RATE CASE

Q What is DEF requesting in this docket related to Crystal River North?

A DEF is requesting to recover the costs of operating and maintaining these units in each of the 2025, 2026, and 2027 Test Years, including additional ongoing capital expenditures ("capex") and O&M spending.[10]

Q Please discuss the level of capital expenditure DEF is requesting for Crystal River North in this rate case.

A In response to discovery questions regarding the amount of capital expenditure included in rate base for Crystal River North, the Company provided data on total Plant in Service, which represents the total value of all of the assets at a plant.[11] My review of the Plant in Service data provided by the Company indicates that Plant in Service total for Crystal River North in 2025 is expected to be $34 million higher than Plant in Service for Crystal River North at the beginning of 2024.[12] This implies the addition of around $34 million in capex in 2024. This is consistent with DEF's historical capex at Crystal River North, which was around $30 million annually from 2019 through 2023.[13]

[10] DEF Minimum Filing Requirements, Schedule B-8, Monthly Plant Balances Test Year – 13 Months.
[11] DEF Response to SC ROG 1-3(a), 3-76(c) (Ex. RA-2).
[12] DEF Response to SC ROG 1-3(a), 1-5 (Ex. RA-2).
[13] DEF Response to SC ROG 1-6(n) (Ex. RA-2).

Q Please discuss the O&M requested for recovery in this rate case.

A DEF is requesting about $47 million in non-fuel O&M spending in the 2025 and 2026 Test Years, and about $45.5 million in the 2027 Test Year.[14] This reflects an increase of 46 percent above historical O&M spending at the plant, which has been $31.4 million a year on average from 2018 through 2023.[15] DEF should explain the reason for this increase in O&M spending in its rebuttal testimony, or its revenue requirement should be revised downward to more closely match historical spending.

Q How might an earlier retirement date for Crystal River North affect the numbers in these rate case requests, and why is it important for DEF to support its requests with an up-to-date retirement evaluation?

A In this rate case, Crystal River North's retirement date is relevant because utilities typically ramp down spending in the last years of a coal plant's life. DEF should consider such a decrease in spending when it calculates its test year spending as part of a rate case. Notably, coal plant economics have changed since the last time DEF evaluated Crystal River North's retirement dates, which was in 2020. Given the new environmental rules discussed in Section 5 of my testimony, and the results of my economic analysis of Crystal River North in Section 6 of my testimony, I find that the Company has substantial reasons to evaluate retiring Crystal River North before 2034.

If Crystal River North were retired in 2030, for example, DEF might have an opportunity to save money for its ratepayers by reducing its level of spending in the 2025, 2026, and/or 2027 test years, as the plant approaches its end of life.

[14] DEF Response to SC ROG 1-4 (Ex. RA-2).
[15] DEF Supplemental Response to SC ROG 1-6(j), (k) (Ex. RA-2).

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DEF's revenue requirement in these test years could be reduced accordingly. However, because DEF has not performed a recent study of early retirement for Crystal River North, it is not possible to know whether the Company's requested level of spending at Crystal River North is justified. DEF's O&M spending projections for Crystal River North in this rate case could be unreasonably high due to the Company's reliance on an outdated 2020 retirement study.

Q Does the Company provide any support in this rate case for its ongoing spending at Crystal River North or its selection of a 2034 retirement date for those units?

A No. DEF appears to rely exclusively on its 2020 study. DEF's testimony and other filed materials in this rate case do not appear to provide any support for the level of ongoing spending at Crystal River North that DEF is projecting. In response to discovery requests regarding the basis for the planned 2034 retirement date, the Company referred to its 2020 analysis of Crystal River North retirement dates, and confirmed that it has not performed a new study of the retirement timing for Crystal River North since then.[16] However, that 2020 analysis is out of date. There have been key market and regulatory changes, including new incentives for clean energy resources made available under the Inflation Reduction Act, volatility in fossil fuel markets, and new U.S. Environmental Protection Agency ("EPA") regulations impacting coal-fired power plants, including new EPA greenhouse gas standards for coal-burning power plants. All of these factors likely render obsolete the 2020 retirement study for Crystal River North.

[16] DEF Response to SC ROG 1-1 (Ex. RA-2).

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5. EARLY RETIREMENT OF CRYSTAL RIVER NORTH

Q Why should DEF evaluate retirement of these units earlier than 2034?

A First, the U.S. EPA recently finalized greenhouse gas standards, which will require coal generators to install equipment to reduce greenhouse gas emissions if they plan to retire after 2032.[17] Under the rule, existing coal plants that do not retire by 2032 must reduce emissions consistent with 40 percent co-firing on gas (a 16 percent reduction in emission rate) by 2030.[18] Accordingly, in order to keep operating until the planned 2034 retirement date, DEF would be required to retrofit Crystal River North to co-fire on gas by 2030.[19] Not only would gas co-firing increase the capital investment needed to keep the plant going, it would also expose the Company to the volatility of gas markets, which have experienced supply disruptions and price increases in recent years. As an alternative, DEF could move Crystal River North's retirement date earlier to avoid all compliance costs associated with the greenhouse gas rule. This would avoid several years of fixed and variable O&M costs, coal price risks, and regulatory risks associated with Crystal River North.

[17] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Elec. Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Elec. Generating Units, 89 Fed. Reg. 39798 (May 9, 2024).
[18] *Id*. at 39838.
[19] *See* U.S. EPA, *Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants* at 6 (Apr. 25, 2024), *available at* https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf. (Exhibit RA-8).

Q Will DEF face any resource adequacy concerns if it retires Crystal River North in 2030?

A No, DEF can maintain a 20 percent capacity reserve margin (that it is currently required to meet) and high level of reliability discussed in its Ten-Year Site Plan by procuring replacement capacity and energy for Crystal River North by 2030. For example, if the Company maintained some or all of its 1,422 MW of contracted winter capacity imports,[20] then it would likely not need any other new capacity resources to safely retire Crystal River North early. Alternatively, the Company could seek new capacity contracts, procure new battery storage or other firm capacity resources through an RFP, or advance planned capacity acquisitions by a few years.

Utilities regularly issue RFPs for resources with online dates one to five years in the future.[21] A 2030 retirement would provide the Company with time to ensure it has adequate capacity and energy to replace Crystal River North.

6. Crystal River North Economic Analysis

Q How have Crystal River North's operating costs compared to the value the plant has provided to the DEF system in recent years?

A Based on the Company's own data, I find that the net value of Crystal River North has been decreasing since 2018, as explained below. Coal fuel costs have

[20] DEF 2024 TYSP at 3-8 (Ex. RA-3).
[21] Portland Gen. Elec., *Procuring Clean Energy* (2023), *available at* https://portlandgeneral.com/about/who-we-are/resource-planning/procuring-clean-energy; PacifiCorp, *2022 All-Source RFP* (Apr. 3, 2024), *available at* https://www.pacificorp.com/suppliers/rfps/2022-all-source-rfp.html.

increased on an average dollar per megawatt-hour ("MWh") basis, while Crystal River North's capacity factor has decreased.

Q Explain the methodology you used to develop this historical analysis.

I used public data, as well as data provided by the Company in discovery, to calculate the cost and estimate the value of Crystal River North between 2018 and 2023. To estimate energy value, I used average values for energy purchases that DEF has made over the last six years.[22] For capacity value, I used the weighted average price of the two largest contracts the Company currently has with third parties for capacity.[23] These estimates are meant to serve as proxies for the cost of replacement energy and capacity. Further, I use the Company's historical data for fuel costs, O&M costs, and capital costs.[24] I net the generator costs and value to find the historical net value (or cost) for each year.

Q How is Crystal River North projected to perform going forward?

A My analysis suggests that the energy and capacity from Crystal River North can be cost-effectively replaced with energy from solar generators and capacity from bilateral contracts at any time (Figure 3). In fact, according to my analysis, the net present value ("NPV") cost of keeping Crystal River North online past 2029 is about $94 million in 2023 dollars. In my analysis, the value of these coal units for customers is negative in nearly every year through 2034.

[22] DEF Response to SC ROG 1-26(a), attach. "SC ROG 1-26a-b Annual Off System Energy Purchases_Sales 2018-2023", Bates No. 20240025-SIERRACLUBROG1-00000025 (Ex. RA-2).
[23] DEF Response to SC ROG 1-24, attach. "Sierra Club Interrogatory 1-24", Bates No. 20240025-SIERRACLUBROG1-00000022 (Ex. RA-2).
[24] DEF Response to SC ROG 1-6(l), (n) (Ex. RA-2).

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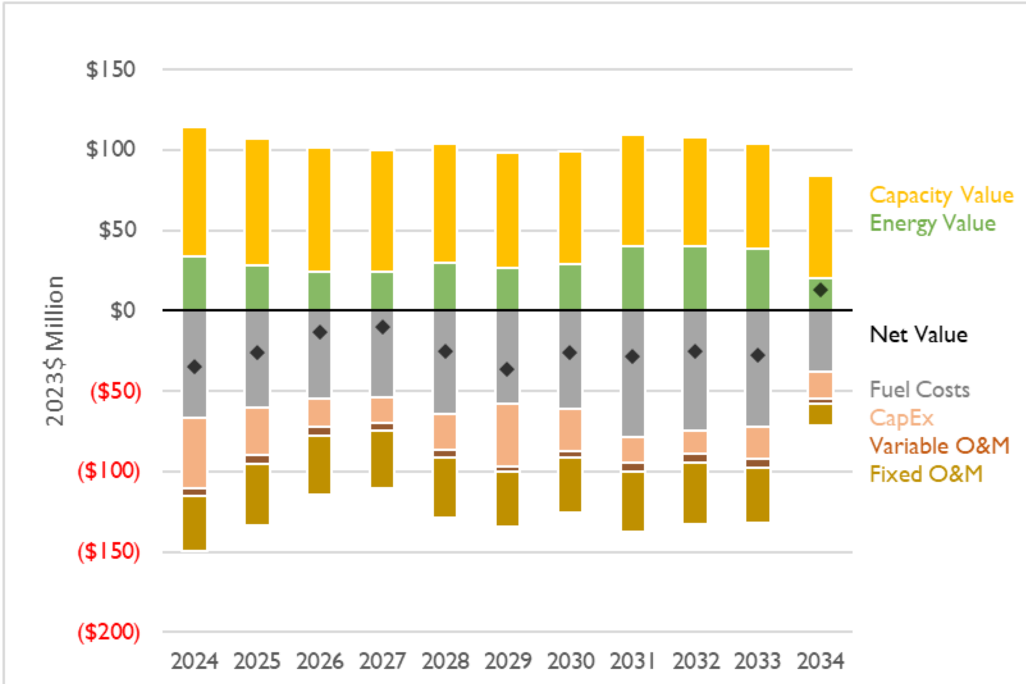
Figure 3. Projected Performance of Crystal River North



Source: DEF Response to SC ROG 1-7, attach. "SC ROG 1-7(a-h_k) Crystal River Units 4_5 Forecasted Generation_Fuel Costs 2024-2034", Bates No. 20240025-SIERRACLUBROG1-0000001, attach. "SC ROG 1-7(m) CRN U4 U5 Investments 2024-2027", Bates Nos. 20240024-SIERRACLUBROG1-00000002-3, attach. "Sierra Club ROG 1 - Q7 i and j", and attach. "Sierra Club Interrogatory 1-24", attach. Bates No. 20240025-SIERRACLUBROG1-00000022); Lawrence Berkeley Lab'y, Photovoltaic PPA Prices, available at https://emp.lbl.gov/pv-ppa-prices (last visited June 10, 2024).

Q Explain the methodology you used to develop this prospective analysis.

A I used public data, as well as data provided by the Company, to compare the energy and capacity value of Crystal River North to forecast costs at Crystal River North from 2024 to 2034.

For a capacity value forecast, I used the costs of capacity contracts the Company currently has with third parties to replace the capacity of Crystal River North.[25] For an energy value forecast, I used data on the average actual costs of solar power purchase agreements ("PPAs") in the Southeast from 2019 through 2023.[26] I included enough solar energy to replace the average expected annual generation at Crystal River North of 1,700 gigawatt-hours ("GWh") per year. This is equivalent to 815 MW of solar with a 22 percent annual capacity factor. I used solar energy as a replacement resource because it is a clean and low-cost source of energy that is not subject to emissions-related regulatory risk or fuel price risk.

For variable and fixed O&M, coal fuel costs, and forecast annual generation, I used cost data provided by DEF in discovery.[27] For the capital expenditure forecast, I used historical spending levels[28] because the forecast provided by the Company was substantially lower than historical spending and did not appear to be a realistic forecast, as explained further below (on page 24).

I netted the generator costs and the generator value to find the forecast net value (or cost) of the plant for each year.

[25] DEF Response to SC ROG 1-24, attach. "Sierra Club Interrogatory", Bates No. 20240025-SIERRACLUBROG1-00000022 (Ex. RA-2).
[26] Lawrence Berkeley Lab'y, *Photovoltaic PPA Prices*, *available at* https://emp.lbl.gov/pv-ppa-prices (last visited June 10, 2024).
[27] DEF Response to SC ROG 1-7, attach. "SC ROG 1-7(a-h_k) Crystal River Units 4_5 Forecasted Generation_Fuel Costs 2024-2034," Bates No. 20240025-SIERRACLUBROG1-0000001, attach. "SC ROG 1-7(m) CRN U4 U5 Investments 2024-2027," Bates Nos. 20240024-SIERRACLUBROG1-00000002-3, attach. "Sierra Club ROG 1 - Q7 i and j" (Ex. RA-2).
[28] DEF Response to SC ROG 1-6(n) (Ex. RA-2).

Q PPA prices have increased in recent years. Why does your analysis use an average cost that is lower than the most recent cost data available for solar PPAs in the Southeast?

A It is true that in recent years, solar PPA costs in the Southeast have increased, likely due to increased demand and various supply constraints. However, DEF does not need to sign a PPA with a third party to procure solar energy. The Company can build large-scale solar projects and earn an authorized rate of return. This should keep costs closer to the actual cost of a solar project and prevent the Company from paying any excessively high solar PPA costs.

In my analysis, a $25.16/MWh value is used as a proxy for the cost to DEF of procuring a large-scale solar project. This is the average solar PPA price in the Southeast based on data from Lawrence Berkeley Laboratory for 2019 through 2023. For comparison, the levelized cost of solar, inclusive of the value of Inflation Reduction Act tax credits, is now expected to be between $19 and $23 per MWh in 2028.[29]

Q Why do you use historical capex costs in your forecast instead of using the forecast provided by DEF?

Since 2018, capital spending has been about $37 million per year on average at Crystal River North.[30] From 2024 to 2028, DEF projects that its capital spending will promptly decrease to about $14 million per year on average beginning in

[29] U.S. Energy Info. Admin., *Levelized Costs of New Generation Res. in the Annual Energy Outlook 2023* at 8, *available at* https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2023_LCOE_report.pdf.
[30] DEF Response to SC ROG 1-6(n) (Ex. RA-2).

2024.[31] It is not totally clear why DEF provided a capex forecast that is about 60 percent lower on average than historical costs. However, based on the Company's response to discovery, it appears that DEF's "projection" of capex spending includes only the amount of Construction Work in Progress ("CWIP") from this rate case, and does not actually reflect the amount the Company is likely to spend on capex at Crystal River North.[32] Given that the Company's projected capital costs deviate significantly from historical spending, and given that the Company's projected capex appears to only include CWIP and not any other capital, I found that the historical cost data was likely to be most representative of the Company's spending in future years. Further, using the Company's forecast of capex on a going-forward basis through 2034 would not change my findings that Crystal River North is operating at a net cost to customers.

Q **What do you conclude from your findings about the economics of continuing to operate Crystal River North?**

A My analysis suggests that the continued operation of Crystal River North is not in the best interest of DEF customers. Retirement of Crystal River North in any year before 2034 would reduce net costs by preventing future spending on O&M and capex, by replacing any needed energy and capacity at lower cost, and by reducing the risk of incurring additional costs from compliance with future environmental regulations. If there were no other major capital projects required at the plant, the savings to ratepayers from retiring Crystal River North in 2030 would be about $94 million.

[31] DEF Response to SC ROG 1-7, attach. "SC ROG 1-7(m) CRN U4 U5 Investments 2024-2027", Bates Nos. 20240024-SIERRACLUBROG1-00000002-3 (Ex. RA-2).
[32] *See* DEF Response to League of United Latin Am. Citizens of Fla. ("LULAC") ROG 1-10(a); *See also* DEF Response to Off. of Pub. Counsel ("OPC") POD 1-7, attach. "B-13 CWIP – REDACTED.xlsx", tab "UI – Additions" (Ex. RA-5).

Q How does the EPA's recently finalized Clean Air Act greenhouse gas rule affect the results of your analysis?

A As noted above, EPA's greenhouse gas rule requires coal generators retiring after 2032 and before 2039 to meet a carbon dioxide emissions standard equivalent to emissions from 40 percent co-firing with gas by 2030.[33] The cost of this upgrade will likely be about $72 million.[34] When this estimated cost of gas co-firing conversion in 2030 is included in my analysis, the NPV savings of closing the plant in 2030, and avoiding the investment in the conversion, increases to $155 million.

7. Risks of Keeping Crystal River North Online through 2034

Q Explain the risks of DEF continuing to operate its coal plant at Crystal River North.

A Operating a coal plant carries fuel price and regulatory risks. Fuel prices can vary unexpectedly, increasing costs for customers due to factors outside the Company's control. Because coal plants have emissions that are subject to regulation, they risk hefty environmental compliance costs to meet environmental regulations that limit emissions and pollutants. In addition, fossil fuels can be subject to global market forces, such as was seen with gas prices during the onset of the 2022 war in Ukraine. The domestic coal industry has also faced challenges

[33] U.S. EPA, *Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants* at 6 (Apr. 25, 2024), *available at* https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf. (Exhibit RA-8).

[34] Sargent & Lundy, *Nat. Gas Co-Firing Memo* at 15 (Mar. 2023), *available at* https://www.epa.gov/system/files/documents/2024-04/attachment-5-11-natural-gas-co-firing-methodology.pdf.

to meet demand, given changing market conditions. This may result in higher coal prices going forward.

Q Explain the risks posed to ratepayers by fuel price volatility.

A Continuing to operate Crystal River North will expose DEF customers to fuel price risk, whether or not the Company retrofits the plant to co-fire on gas. Resources that require fuel to operate, such as coal and gas generators, are subject to fuel price risk throughout their lifetimes. Although coal can be stored on site to hedge against price volatility, fuel storage capacity is finite and carries a cost. In addition, supply is limited in some parts of the country. Coal prices are often subject to multi-year contracts, so their volatility tends to be lower in the short term, whereas gas prices can vary greatly by the day. Hedging can be used to manage volatility in the gas market, but comes at a cost premium.

Q Explain the risks posed to ratepayers from continued reliance on coal.

A The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[35] There have also been labor challenges both at the mines and the railroad companies that transport the coal. Additionally, as more coal plants across the United States retire and the demand for coal decreases, this trend, combined with labor challenges, could result in consolidation or bankruptcy among coal companies and subsequently higher coal prices.[36]

[35] U.S. Energy Info. Admin., *Coal Mkts.* (June 10, 2024), *available at* https://www.eia.gov/coal/markets/.
[36] Duke Energy, *Carolinas Res. Plan, App. F: Coal Retirement Analysis* (2023), *available at* https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-f-coal-retirement-study.pdf?rev=4c1c4df441a14248b2e23ba0368d9855.

Coal use was down in 2023 and never reached more than 20 percent of power market share (through October).[37] This is novel because market share had been around 20 percent each month between 2020 and 2022, and prior to 2020, coal had never comprised less than a 20 percent market share in any month.[38] Additionally, increased environmental regulation could result in higher costs and higher risks. Higher regulatory risk impacts not just resource planning economics, but also company risk profiles, which can lead to downgraded credit ratings and impact access to capital.

Additionally, break-downs of parts and a lack of continued support from manufacturers based on the old age of coal plant technology can result in sustained outages and challenges in quickly repairing units and getting them back online.

8. Undepreciated Plant Balance and the Energy Infrastructure Reinvestment Program

Q Please summarize your findings regarding undepreciated plant balance and the EIR.

A As I have shown above, early retirement of Crystal River North will provide benefits to customers. Strictly accelerating depreciation of the balance to align the book life with an earlier economic retirement date for the plant, though, may result in rate shock to customers. Fortunately, there are other tools and

[37] Seth Feaster, *Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024*, Inst. for Energy Econ. and Fin. Analysis (Nov. 2, 2023), *available at* https://ieefa.org/resources/coal-use-us-power-plants-continues-downward-spiral-full-impact-mines-be-felt-2024.
[38] *Id.*

alternatives utilities can use to manage and mitigate the impacts to ratepayers, as I will discuss below.

Q Please describe the approximate effect on DEF's annual revenue requirement of accelerating the Crystal River North depreciation end date from 2034 to 2030 without any other efforts to manage ratepayer impacts.

As of 2024, the undepreciated book value of Crystal River North is approximately $1.3 billion.[39] Changing the depreciation end date from 2034 to 2030 would accelerate and shorten the plant's depreciation schedule and bring forward some of those costs. Because customers would need to pay these costs sooner instead of later, the present value revenue requirement ("PVRR") would increase. This would reduce the direct benefits of early retirement, but would not offset the benefits to customers of reduced fuel price volatility and regulatory risks.

Accelerated depreciation is a fairly typical way to deal with cost recovery when a retirement date is moved forward. But because of the impact on customers, utilities often utilize other methods to mitigate the impacts of accelerated depreciation from an early retirement.

Q What potential methods are there to reduce the impacts of accelerated depreciation?

A The impacts of accelerated depreciation can be reduced through the use of a regulatory asset or through EIR funding.

A regulatory asset is sometimes used to recover a retiring plant's undepreciated balance using a somewhat longer timeframe than the plant's operational lifetime.

[39] DEF Response to SC ROG 1-5 (Ex. RA-2).

For example, Crystal River North could be retired in 2030, while its plant balance is recovered in a regulatory asset through 2032. Because customers have longer to pay off the plant balance, the rate impact of acceleration is decreased. For example, Southwestern Electric Power Company has a regulatory asset for the Balance of the Dolet Hills Power Plant.[40]

As I will describe in more detail below, the U.S. DOE's EIR program can allow a plant balance to be recovered over a longer timeframe and at a lower rate of return, and this should not require approval from a state legislature.

Q Please provide a general overview of the EIR program.

A The EIR program, established under the Inflation Reduction Act, provides DOE with $250 billion in loan authority that it can deploy to "retool, repower, repurpose, or replace" fossil infrastructure.[41] The loans are available at just above the federal government's cost of borrowing with repayment periods of up to 30 years—which means they offer a significantly cheaper method of financing the undepreciated balance of coal plants than accelerated depreciation or the use of a regulatory asset.[42] Per statute, utilities are required to pass through the savings enabled under the EIR to their customers.[43]

[40] Tex. Pub. Util. Comm'n Order, Control No. 51415, Item No. 705.
[41] U.S. Dep't of Energy, Loan Programs Off., *Program Guidance for Title 17 Clean Energy Fin. Program* at 7 (May 19, 2023), *available at* https://www.energy.gov/lpo/articles/program-guidance-title-17-clean-energy-program#page=1 [hereinafter "U.S. DOE, Loan Programs Off., *Programs Guidance for Title 17 Clean Energy Fin. Program*"].
[42] *Id.* at 8.
[43] U.S. Dep't of Energy, Loan Programs Off., *Energy Infrastructure Reinvestment, available at* https://www.energy.gov/lpo/energy-infrastructure-reinvestment (last visited June 10, 2024).

EIR loans are intended to finance investment in replacement generation capacity, distribution upgrades, or other investments that can help enable greenhouse gas emission reductions. And while the total loan amount is capped at 80 percent of the replacement project cost, the funding can be used to both lower the project costs for replacement resources and address legacy asset plant balances. In other words, the loans can be used to refinance the outstanding asset balances of existing legacy coal units.[44]

Q How might the EIR program help customers avoid the increased revenue requirement from accelerated depreciation?

A The EIR program provides low-cost loans for utilities that have plans to retire fossil fuel assets and replace them with clean energy.[45] The low cost of capital can help reduce the costs of new resources. The loans may potentially also be used to refinance plant balances—moving some of the plant balance to a dedicated surcharge financed at a lower rate and recovered over a longer timeframe—and thus avoid the cost increase associated with accelerated depreciation for customers.

[44] Christina Fong et al., *The Energy Infrastructure Reinvestment Program: Fed. Fin. for an Equitable, Clean Econ,* RMI (Feb. 16, 2024), *available at* https://rmi.org/the-energy-infrastructure-reinvestment-program-federal-financing-for-an-equitable-clean-economy/ [hereinafter "Christina Fong et al., *The Energy Infrastructure Reinvestment Program: Fed. Fin. for an Equitable, Clean Econ*"].

[45] U.S. DOE, Loan Programs Off., *Programs Guidance for Title 17 Clean Energy Fin. Program* at 6.

Q Approximately how much might the EIR save customers if it were used to help fund the replacement of Crystal River North with renewable energy?

A A recent analysis by the Rocky Mountain Institute looks at a similar utility procurement and retirement scenario to the one that DEF customers are facing.[46] The analysis finds that an EIR loan, combined with a dedicated rate surcharge to help support early retirement and replacement, could avoid the effects of accelerated depreciation and save an additional $123 million or more for ratepayers.[47] Based on this, I believe that the EIR program has the potential to deliver a similar level of savings to DEF ratepayers if the Company submits an application and uses an EIR loan to facilitate the retirement and replacement of Crystal River North.

Q Please further explain the savings that could be achieved using EIR funding.

A The Rocky Mountain Institute study referenced above examines a case study of Alliant Energy's retirement of a coal asset and replacement with renewable energy in Iowa. Alliant's resource plan has a similar cost to the approximately 815 MW of solar that would be needed to replace the energy of Crystal River North. There are two potential ways to use the EIR program to support a retirement and replacement plan similar to Alliant's.

The first approach to using EIR funding to support Alliant's plan would be to use low-cost EIR funding to finance 20 percent of the renewable additions and create a dedicated rate surcharge for customers to repay the loan. This example assumes

[46] Christina Fong et al., *The Energy Infrastructure Reinvestment Program: Fed. Fin. for an Equitable, Clean Econ.*
[47] *Id.*

that Alliant finances only 20 percent of its planned $855 million investment in new renewables through EIR, while the EIR program can potentially cover up to 80 percent of project costs.[48] Financing 20 percent of new renewables through the EIR program would allow Alliant to earn its usual rate of return on 80 percent of the new renewable investment, and customers would save $57 million after transaction costs.[49] This is a cautious estimate of potential customer benefits because it does not maximize the amount of the EIR loan.

The second approach increases customer benefits by also using EIR funding to address some of the undepreciated plant balance at a retiring coal plant. Alliant's Lansing plant is estimated to have a $256 million undepreciated balance. By adding this amount to Alliant's EIR loan, the Lansing undepreciated balance could be removed from the utility's books and recovered through a dedicated surcharge financed at EIR loan rates and recovered over up to 30 years. The total EIR loan amount would still be less than 80 percent of new project costs, as required, and the utility would still earn a rate of return on 80 percent of the new capital investment. However, ratepayers would enjoy up to 30 years to repay the EIR loan at a lower interest rate, instead of paying increased costs from accelerated depreciation. Total customer savings for Alliant from using EIR funding in this way would be $123 million.[50]

DEF could realize a similar amount of savings by using the EIR to fund the earlier retirement of Crystal River and its replacement with alternatives. In addition to the $155 million in benefits from 2030 retirement of Crystal River that I estimate

[48] U.S. DOE, Loan Programs Off., *Programs Guidance for Title 17 Clean Energy Fin. Program* at 9.
[49] *Id.*
[50] Christina Fong et al., *The Energy Infrastructure Reinvestment Program: Fed. Fin. for an Equitable, Clean Econ.*

in my economic analysis above, adding this conservative estimate of $123 million in additional savings from the EIR program would result in a total customer benefit of about $278 million.

Q Has DEF applied for EIR funding or evaluated the potential to utilize funding from the EIR program to finance replacement resources or refinance undepreciated plant balances?

A No. DEF has not applied for EIR funding and currently has no plans to do so.[51] DEF has also not conducted any analysis of the potential benefits from the EIR program.[52]

Q What is your recommendation regarding EIR funding?

A DEF should use EIR funds to reduce the costs of new renewable generation and re-finance a portion of the Crystal River North plant balance. To begin this process, DEF should submit an application to DOE's Loan Program Office for EIR funding. The Commission should direct DEF to evaluate potential funding from the EIR program and apply for funding.

[51] DEF response to SC ROG 4-95 (Ex. RA-2).
[52] *Id.*

9. <u>Winter Capacity Contribution of Solar</u>

Q Please describe the Company's winter capacity position now and through 2030.

A DEF currently has a 37 percent winter capacity reserve margin.[53] This is much higher than the 20 percent reserve margin that DEF agreed to adopt in a 1999 Stipulation.[54] The Company's winter reserve margin is expected to decrease gradually to 23 percent by 2030 as its demand grows and some resources are removed from service.[55]

Q How does DEF calculate its winter reserve margin?

A The winter reserve margin in the Company's TYSP appears to be calculated based on a comparison of the Company's forecast peak winter load to the amount of firm resource capacity available each winter in the EnCompass model's capacity expansion run. The reserve margin is the amount of excess capacity expected to be available above the forecast peak load.

Q Please discuss the EnCompass model planning exercise in the TYSP.

A In the TYSP, DEF uses the EnCompass model to develop a portfolio of planned resources to meet system needs over the next ten years.[56] The model is designed to create a portfolio that meets system needs reliably at the lowest cost. DEF

[53] DEF 2024 TYSP at 3-8 (Ex. RA-3).
[54] Order No. PSC-99-2501-S-EU. Attachment A at 2.
[55] DEF 2024 TYSP at 3-8 (Ex. RA-3).
[56] DEF 2024 TYSP at 3-48 (Ex. RA-3).

states that EnCompass is given a 20 percent reserve margin requirement.[57] DEF states that the 20 percent reserve margin typically results in an EnCompass portfolio that meets a high reliability standard without further resource additions.[58] This indicates that a 20 percent reserve margin is generally more than adequate for planning a reliable system for DEF.

Q How does DEF treat the winter capacity contribution of solar in its EnCompass modeling and reserve margin calculation?

A DEF assumes that the firm capacity contribution of solar resources is zero in the winter.[59] However, DEF has not performed any analysis to support that assumption.[60] That means that even if solar facilities help DEF meet demand during some peak winter hours, the solar in DEF's modeling and reporting will receive no credit for the capacity value it provides.

Q What reason might DEF have for using a zero value for capacity contribution of solar?

A DEF may be using a zero value for solar winter capacity contribution in part because the Florida Reliability Coordinating Council ("FRCC") says that for

[57] DEF 2024 TYSP at 3-47 (Ex. RA-3).
[58] *Id.*
[59] Benjamin Borsch Deposition Transcript Vol. 2 (May 30, 2024) at 159:11-14 (Ex. RA-6); Reginald Anderson Deposition Transcript Vol. 2 (May 24, 2024) at 171:13-16 (Ex. RA-7); DEF Response to SC ROG 30, attachment "SC ROG-1 Q30 Excel" at 5, Bates No. 20240025-SIERRACLUBROG1-00000033 (Ex. RA-2).
[60] Borsch Deposition Transcript Vol. 2 (May 30, 2024) at 161:12-16.

winter, solar typically receives no firm capacity value.[61] It is not clear that DEF or the FRCC have done any analysis to show that solar has no capacity contribution in winter. It may be a simplifying assumption used for convenience. And the FRCC notes the need for ongoing study, stating, "This firm capacity contribution from solar will continue to be monitored as solar becomes a larger and larger part of FRCC member company's resource mix[.]"[62]

This lack of analysis by DEF is concerning, especially since the Company's sister utilities, Duke Energy Progress and Duke Energy Carolinas, hired Astrapé to conduct an Effective Load Carrying Capability ("ELCC") study as part of their most recent IRP process.[63] This study found a winter solar capacity value of between 6.1 and 3.4 percent based on the unique characteristics of that system.[64] DEF should utilize the same level of rigor in its resource planning in Florida that Duke Energy uses elsewhere in the country.

Q What evidence do you have that solar does have some winter capacity contribution?

A DEF Witness Benjamin Borsch noted that solar likely provides 2-3 percent of capacity contribution in the winter—yet Duke assumes a capacity contribution of

[61] Florida Reliability Coordinating Council, 2022 Load & Resource Reliability Assessment Report, FRCC-MS-PL-397, at 28, available at: https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans/2022/FRCC_Presentation.pdf.
[62] *Id.*
[63] Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study, Astrapé Consulting (April 25, 2022), available at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=9713b7f8-ebc3-4b97-ac34-154d65df98cf. (Exhibit RA-10).
[64] *Id.* at 10.

zero percent.[65] Additionally, as mentioned above, the results from Duke's ELCC study in the Carolinas indicate that utilities in the southeastern United States have found solar to have a small but meaningful winter capacity contribution.

This is relevant because by 2034, DEF expects to have more than 6,100 MW of solar online.[66] If this solar provides a 2 percent capacity contribution, giving it proper credit for this contribution could reduce DEF's winter capacity need by about 122 MW. At an approximate cost of $1,422/kW for new capacity, that is equivalent to potentially saving customers $174 million in installed costs alone.[67]

Q What do you recommend regarding winter capacity?

A I recommend that DEF perform or commission an ELCC study of the capacity contribution of solar, including during winter. A rigorous analysis would likely reduce the amount of incremental capacity that DEF needs to meet its 20 percent reserve margin. It will also potentially save ratepayers millions of dollars by avoiding procuring capacity that they do not need to reliably serve load.

Q Does this conclude your testimony?

Yes.

[65] Borsch Deposition Transcript (May 30, 2024), Vol. 2, at 160:14-161:11 (Ex. RA-6).
[66] DEF 2024 TYSP at 1 (Ex. RA-3).
[67] DEF 2024 TYSP at 3-31 (Ex. RA-3).

(Whereupon, prefiled direct testimony of Angela Calhoun was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240025-EI – Petition for rate increase by Duke Energy Florida, LLC

Witness: Direct Testimony of **Angela L. Calhoun**, Florida Public Service Commission;

Appearing on Behalf of the Staff of the Florida Public Service Commission

DATE FILED: June 11, 2024

C37-4050

DIRECT TESTIMONY OF ANGELA L. CALHOUN

Q. Please state your name and address.

A. My name is Angela L. Calhoun. My address is 2540 Shumard Oak Boulevard; Tallahassee, Florida 32399-0850.

Q. By whom are you employed and in what capacity?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as Chief of the Bureau of Consumer Assistance in the Office of Consumer Assistance & Outreach.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from Florida State University in 1993 with a Bachelor of Arts degree. I have worked for the Commission for more than 24 years, and I have experience in consumer complaints and consumer outreach. I work in the Bureau of Consumer Assistance within the Office of Consumer Assistance & Outreach where I manage consumer complaints and inquiries.

Q. What is the function of the Bureau of Consumer Assistance?

A. The Bureau's function is to resolve disputes between regulated companies and their customers as quickly, effectively, and inexpensively as possible.

Q. Do all consumers that have a dispute with their regulated company contact the Bureau of Consumer Assistance?

A. No. Consumers may initially file their complaint with the regulated company and reach a resolution without the Bureau's intervention. In fact, consumers are encouraged to allow the regulated company the opportunity to resolve the dispute prior to any Commission involvement.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss/outline the number of consumer complaints logged with the Commission against Duke Energy Florida, LLC (DEF) under Rule 25-22.032, Florida Administrative Code, Consumer Complaints, from April 1, 2019 through March 31, 2024. My testimony will also provide information on the type of complaints logged and those complaints that appear to be rule violations.

Q. What do your records indicate concerning the number of complaints filed for DEF?

A. From April 1, 2019 through March 31, 2024 the Commission logged 4,144 complaints against DEF. Of those, 2,296 were transferred to the company for resolution via Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to DEF customer service personnel. Once the call is transferred to DEF, the Company can provide the customer with a proposed resolution.

Q. What have been the most common types of complaints logged against DEF during the period of April 1, 2019 through March 31, 2024?

A. During the specified time period, approximately sixty-three (63%) percent of the complaints logged with the Commission concerned billing issues, while approximately thirty-seven (37%) percent of the complaints involved quality of service issues.

Q. Do you have any exhibits attached to your testimony?

A. Yes. I am sponsoring ALC-1 and ALC-2, which are listings of consumer complaints logged with the Commission against DEF under Rule 25-22.032, Florida Administrative Code. The complaints listed were received between April 1, 2019 through March 31, 2024, and were captured in the Commission's Consumer Activity Tracking System (CATS). Exhibit ALC-1 lists quality of service complaints and Exhibit ALC-2 lists billing complaints. Both exhibits group the complaints by Close Type.

Q. What is a Close Type?

A. A Close Type is an internal categorization code. It is assigned to each complaint once staff completes its investigation, and a proposed resolution is provided to the consumer.

Q. Do you have any additional exhibits?

A. Yes. Exhibit ALC-3 is a listing of complaints resolved as Close Type GI-02, Courtesy Call/Warm Transfer.

Q. Can you explain Close Type GI-02?

A. Yes. DEF participates in the Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to the company's customer service personnel. Once the call is transferred to DEF it provides the customer with a proposed resolution. Customers who are not satisfied with the company's proposed resolution have the option of re-contacting the Commission. While the Commission is able to categorize each of the complaints in the GI-02 category, a specific Close Type is not assigned because the proposed resolution is provided by the company. Consequently, the GI-02 Close Type only allows staff to monitor the number of complaints resolved via the Commission's Transfer-Connect System.

Q. How many of the complaints summarized on your exhibit has staff determined may be a violation of Commission rules for DEF?

A. Staff determined that, of the 4,144 complaints logged against DEF during the period of April 1, 2019 through March 31, 2024, there were 12 service quality complaints and 91 billing complaints that appear to demonstrate a violation of Commission Rules.

Q. Does that conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Simon Ojada was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240025-EI – Petition for rate increase by Duke Energy Florida, LLC

Witness: Direct Testimony of **Simon Ojada**, Florida Public Service Commission;

Appearing on Behalf of the Staff of the Florida Public Service Commission

DATE FILED: June 11, 2024

C38-4210

DIRECT TESTIMONY OF SIMON OJADA

Q. Please state your name and business address.

A. My name is Simon Ojada. My business address is 2540 Shumard Oak Blvd; Tallahassee, FL 32399.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst. I retired from the Commission in January 2023 after 26 years of employment, and I returned in April 2024 following a brief retirement.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from the University of South Florida in 1991 with a Bachelor of Science degree in Finance. In 1994, I received a Bachelor of Science degree in Accounting from Florida Metropolitan University. In 1997, I received a Master of Business Administration with a concentration in Accounting from Florida Metropolitan University. As a 26-year employee of the Commission, I have varied experience in the electric, gas, and water and wastewater industries. My work experience includes various types of rate cases, cost recovery clauses, and utility audits.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I have presented testimony in several dockets before this Commission. Those dockets include Docket Numbers 20130001-EI, 20140001-EI, 20150001-EI, 20160001-EI, 20170001-EI, 20180001-EI, and 20190001-EI.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor staff's Auditor Report of Duke Energy Florida, LLC which addresses the Utility's filing in Docket No. 20240025-EI. An Auditor's Report was filed in the docket on June 7, 2024. This report is filed with my testimony and is identified as Exhibit SO-1.

Q. Was this audit prepared by you or under your direction?

A. Yes. It was prepared under my direction.

Q. Please describe the objectives of the audit and the procedures performed during the audit?

A. The objectives and procedures are listed in the Objectives and Procedures section of the attached Exhibit SO-1, pages 2 through 6.

Q. Were there any audit findings in the Auditor's Report (Exhibit SO-1) which address the schedules prepared by the Utility in support of its filing in Docket No. 20240025-EI?

A. No.

Q. Does that conclude your testimony?

A. Yes.

C38-4212

(Transcript continues in sequence in Volume 7.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 4th day of September, 2024.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028