Moyle
LAW FIRM

June 6, 2024

Electronic Filing

Mr. Adam J. Teitzman, Commission Clerk
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oaks Boulevard
Tallahassee, Florida 32399-0850

Re: Docket 20240026-EG Petition for Rate Case Increase by Tampa Electric Company

Dear Mr. Teitzman:

Please find attached the intervenor testimony of witness Jeff Pollock provided on behalf of the Florida Industrial Power Users Group ("FIPUG").

Thank you for your assistance in filing this testimony.

Sincerely,

Jon C. Moyle, Jr.

Attachment
cc: All Parties of Record (with attachment)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI** **Filed: June 6, 2024**

DIRECT 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 Tampa Electric Company	**DOCKET NO. 20240026-EI Filed: June 6, 2024**

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JP-4	FIPUG's Revised Class Cost-of-Service Study
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GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
2021 Agreement	Stipulation and Settlement Agreement in Docket No. 20210034-EI
AD	Average Demand
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost-of-Service Study
CT	Combustion Turbine
FIPUG	Florida Industrial Power Users Group
Future Solar Projects	TECO's Eight Proposed Solar Facilities
IOU	Investor-Owned Utility
Gulf Power	Gulf Power Company
kW / kWh	Kilowatt / Kilowatt-Hour
MDS	Minimum Distribution System
MFR	Minimum Filing Requirement
MW / MWh	Megawatt(s) / Megawatt-Hour
O&M	Operation and Maintenance
PTC	Production Tax Credit
ROE	Return on Equity
RRA	Regulatory Research Associates
TECO	Tampa Electric Company

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). A substantial number of FIPUG members purchase electricity from Tampa Electric Company (TECO). 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 issues raised in and the outcome of this proceeding.

Q WHAT ISSUES DO YOU ADDRESS?

A First, I present an overview of TECO's proposals, including 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 TECO's proposed eight "Future 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-6**.

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

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

<u>Summary</u>

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

<u>Overview</u>

- TECO's proposed base revenue increase and subsequent year adjustments are being driven by $2.6 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 10.2% under the Stipulation and Settlement Agreement (2021 Agreement) which resolved TECO's last rate case in 2021 to 11.5%.[1]

- Approximately $786.4 million of plant additions are for eight Future Solar Projects. As Mr. Ly testifies, the cost-effectiveness of the Future Solar Projects is highly questionable.

- TECO's proposed 11.5% ROE is 172 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 (38% to 43%) of TECO'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 TECO faces significantly less regulatory risk than many of its peer IOUs. Accordingly, the lower regulatory risk should be reflected in the ROE authorized for TECO.

<u>Class Cost-of-Service Study</u>

- TECO is proposing to set rates using a CCOSS that allocates production and transmission plant and related expenses using the Four Coincident Peak (4CP) method. Additionally, TECO is proposing to classify a portion of the distribution network as a customer-related cost – a process referred to as Minimum Distribution System (MDS).

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[1] *In re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 20210034-EI, Corrected 2021 Agreement at 5-6 (Oct. 13, 2021). See also, *Final Order Approving Stipulation and Settlement Agreement Between Tampa Electric Company and All Intervenors* (Nov. 10, 2021) and Letter indicating "Trigger Mechanism" has gone into effect (Oct. 25, 2021).

- The 4CP method recognizes the reality that TECO is a strongly 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. The 4CP method is based on demands that occur coincident with the (January, June, July, and August) test-year peak demand. 4CP recognizes that it is the summer with a secondary winter peak demands that primarily drive the need for new capacity additions to maintain reliability. Furthermore, TECO experiences its lowest reserve margins during the summer months — this is also when the transmission system experiences its lowest load carrying capability.

- 4CP is a necessary improvement over the Twelve Coincident Peak (12CP) method that has been used in past rate cases. 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, TECO would not be able to serve all of its load during the peak periods. In contrast, the 4CP approach and analysis is focused on cost causation.

- TECO's MDS analysis should be adopted. MDS classifies a portion of the distribution network as a customer-related cost. This is consistent with the principles of cost causation; that is, when TECO 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 TECO in their last rate cases.

- Production tax credits (PTCs) were allocated in the same manner as production rate base. However, unlike investment tax credits, which reduce production capital costs, production tax credits are earned for every megawatt-hour (MWh) generated by a TECO-owned solar project. Accordingly, PTCs should be allocated on an energy basis.

Class Revenue Allocation

- TECO has followed the Commission's long-standing policy to move all rates closer to cost using a proper CCOSS.
- The proper application of gradualism would be 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

- TECO is proposing to eliminate seasonal rates to achieve simplicity and understandability. TECO is also proposing to implement a "Super Off-Peak" period that would establish very low energy prices during the daytime hours year-round.
- Notwithstanding its recent investments in renewable generating assets, TECO remains a strongly summer-peaking system, and these system peaks have occurred during daytime hours.
- The proposed Super Off-Peak period is also based on an assumption that TECO will continue to expand its investment in renewable generating assets. However, it is highly questionable whether TECO has adequately demonstrated that the proposed Future Solar Projects are cost-effective, as discussed fully by my colleague, Mr. Ly.
- Eliminating seasonal rates is not consistent with cost causation. Further, it is premature to establish a Super Off-Peak period during daytime hours to reflect existing and continued renewable investment. Both changes would send the wrong price signals as well as complicate matters for customers, contrary to TECO's stated intentions. Accordingly, the Commission should reject these rate design proposals.

2. OVERVIEW

Q WHAT BASE RATE INCREASES IS TECO PROPOSING TO IMPLEMENT?

A TECO is proposing a $296.6 million (20%) base revenue increase in 2025 followed by subsequent year adjustments of $100 million (5.6%) in 2026 and $71.8 million (3.8%) in 2027.[2]

Q HAVE ANY OTHER BASE RATE INCREASES BEEN IMPLEMENTED RECENTLY?

A Yes. TECO implemented three base rate increases pursuant to the 2021 Agreement. The last of these increases was implemented just this year. Over the three years, the cumulative base revenue increase was 21.2%.

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

A TECO expects to add nearly $2.6 billion of rate base through 2027. Of the $2.6 billion of rate base additions, $1.2 billion is comprised of:

- Eight new solar projects: $786.4 million;[3]
- Four new two-hour battery energy storage system projects: $156 million;[4] and
- Various resiliency projects: $294.4 million.[5]

An additional $523.7 million of rate base additions is for office and support spaces.[6]

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2 Petition at 5, 10.

3 Prepared Direct Testimony and Exhibit of Kris Stryker at 8.

4 *Id*. at 29.

5 Prepared Direct Testimony and Exhibit of Carlos Aldazabal at 44, 49-50, 68.

6 *Id.* at 57, 65.

Additionally, TECO is proposing higher depreciation and dismantling expenses and a much higher cost of capital. This includes an increase in ROE from 10.2% to 11.5% ROE.[7] ***The 130-basis points of higher ROE drives about $80 million (nearly 20%) of the proposed $468.5 million base revenue increase.***

Q PLEASE DESCRIBE THE PROPOSED NEW SOLAR PROJECTS.

A The Future Solar Projects represent about 490 megawatts (MW) of *nameplate* capacity. Two projects will be commissioned in December 2024, two projects in December 2025, and four projects will be commissioned between May and December 2026. TECO estimates that the Future Solar Projects (including land) would cost $1,609 per kilowatt (kW). When complete, TECO projects that solar will provide approximately 18% of customer energy needs.

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

A TECO asserts that the Future Solar Projects would save $798 million in fuel costs over their expected 35-year lives and generate another $252 million in PTCs.[8] However, Mr. Ly has determined that $157 million of these savings are avoided carbon emissions that are valued based on a hypothetical, non-existent carbon tax or fee. Further, the projected PTCs, which comprise a significant portion of the benefits of the Future Solar Projects, are dependent upon these resources generating at the levels expected by TECO. Thus, it is essential to condition approval of these projects by

[7] Petition at 6.

[8] Prepared Direct Testimony and Exhibit of Jose Aponte, Exhibit No. JA-1, Document No. 11.

imposing a construction cost cap and performance guarantees to ensure that customers actually receive the benefits projected, as discussed by Mr. Ly.

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

A TECO's proposed 11.5% 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 2024 through May 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 MORE RISKY 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 a projected test year 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 adopted 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-adopted 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 adopted 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)[9] (emphasis added)

The Commission's ranking remains at Above Average/2.[10] Only one state regulatory commission, Alabama, is ranked higher than the Florida Commission.

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

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

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

A TECO collected between 38% and 43% of its annual sales revenues under each of the five currently-effective cost-recovery mechanisms, as shown in Table 1.

Table 1
Percent of Revenues Collected Under the Various Commission-Approved Cost Recovery Mechanisms

Mechanism	2023	2024	2025
Fuel	36%	30%	28%
Conservation	2%	1%	3%
Environmental	1%	1%	1%
Storm Protection	2%	4%	4%
CETM	2%	3%	3%
Total Cost Recovery	43%	38%	38%

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 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 TECO?

A The absence of any appreciable regulatory lag in setting base rates also reduces TECO's regulatory risk. This, coupled with this Commission's other supportive ratemaking policies (*i.e.,* future rather than historical test year, the ability to adjust rates outside of a base rate case through separate cost recovery mechanisms) demonstrate how TECO's regulatory risk is no higher (and arguably lower) than for most other regulated vertically integrated electric IOUs. Therefore, the lower regulatory risk should translate into a lower ROE than for 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 TECO FILED ANY CLASS COST-OF-SERVICE STUDIES IN THIS PROCEEDING?

A Yes. TECO filed two CCOSSs:

- 4CP/MDS; and
- 12CP & 1/13th (or 8%) Average Demand (AD) – *i.e.,* 12CP+8% AD.[11]

Of the two studies, TECO (and FIPUG) supports the 4CP/MDS.

[11] Note, this approach is often referred to as Peak and Average and is used interchangeably with 12CP+8% AD herein.

Q WHAT IS THE DIFFERENCE BETWEEN THE 4CP/MDS AND 12CP+8% AD CLASS COST-OF-SERVICE STUDIES?

A The 4CP/MDS CCOSS allocates production and transmission plant using the 4CP method. As discussed later, 4CP allocates costs based on each rate class's demand that is projected to occur coincident with (*i.e.,* on the same date and hour as) the system peak demands in the months January, June, July, and August. MDS classifies a portion of the distribution network as a customer-related costs. As discussed later, the distribution network includes plant investment in FERC Account Nos. 364-367 and related expenses. Customer-related distribution plant and related costs are allocated based on the number of customers in each customer class, while the corresponding demand-related network costs are allocated on each class's peak demand, irrespective of when that peak demand occurs.[12]

The 12CP+8% AD study allocates approximately 92% of production and transmission plant based on each rate class's demand that is projected to occur coincident with each of the 12 monthly system peaks and approximately 8% on each rate class's share of Florida retail average demand. Average demand is the same as allocating costs on an annual energy usage.

Q WHICH STUDY IS PREFERABLE?

A As explained later, 4CP/MDS is preferable to the 12CP+8% AD.

[12] As discussed in **Appendix C**, distribution facilities are electrically closer to customers than generation and transmission facilities. Thus, using each class's peak demand (rather than the demand coincident with the system peak or CP demand) best reflects the expected demand that determines how distribution facilities are sized.

Q DO YOU HAVE ANY CONCERNS WITH EITHER THE 4CP/MDS OR 12CP+8% AD CLASS COST-OF-SERVICE STUDY?

A Yes. In both studies, TECO allocated PTCs on production rate base. However, PTCs are earned on each MWh that is generated from TECO's owned solar plants over the first ten commercial operating years. Thus, PTCs should be allocated on an energy basis.

<u>Allocation of Production and Transmission Costs</u>

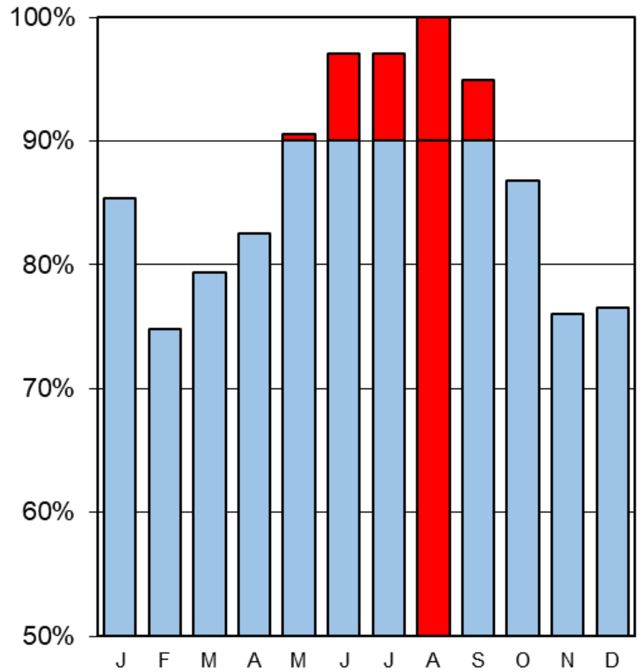
Q PLEASE EXPLAIN THE 4CP METHOD.

A The 4CP method allocates costs based on each class's projected coincident peak during the months January, June, July, and August of the test year.

Q IS THE 4CP METHOD CONSISTENT WITH COST CAUSATION?

A Yes. Peak demand drives cost causation. In order to meet its obligation to serve firm loads, electric utilities must plan to install sufficient capacity to meet the expected peak demand with a cushion for unplanned outages, unexpected weather, and load forecast error. The 4CP method reflects the reality that TECO's load is highly weather-sensitive. Although TECO has historically been a summer-peaking utility, it has, on occasion, experienced a winter peak. A history of TECO's monthly system peaks is provided in **Exhibit JP-2**, which is also summarized in Chart 1 on the following page.

Chart 1
Monthly Peak Demands as a Percent of
The Annual System Peak: 2020-2025



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

Q IS TECO PROJECTING TO REMAIN SUMMER PEAKING?

A No. TECO is currently projecting a winter peak in January 2025 (the test year). Further, TECO is also projecting more peak load growth during the winter months than during the summer months.[13] As a result, TECO is now projecting to become a winter-peaking utility. For this reason, TECO included January in addition to the summer months June through August in applying the 4CP method.

[13] TECO's Ten-Year Site Plan January 2024 – December 2033 at 20.

Q WHY IS TECO SUPPORTING 4CP?

A Among the reasons cited by TECO is that 4CP reflects cost causation. Specifically, TECO witness, Jordan Williams, states:

> (1) The 4 CP methodology reflects cost causation in relation to Tampa Electric's peak demands. Tampa Electric's peaks are primarily a function of energy consumption associated with weather. There is a strong correlation between weather and residential and small commercial energy consumption. When it is hot, those rate classes tend to consume more energy through cooling, and when it is cold, those rate classes tend to consume more energy through heating. Tampa Electric's large commercial and industrial customers tend to be high load factor customers and are not as strongly correlated with weather, so their energy consumption stays fairly consistent throughout the year. Since the residential and small commercial rate classes are highly correlated with weather, they are the rate classes that cause Tampa Electric's peaks, so they are allocated costs based on cost causation.[14]

Mr. Williams also cites the fact that the Commission approved the 2021 Agreement in which the parties agreed to allocate production and transmission demand-related costs using the 4CP method.[15]

Q DOES THE COMMISSION REQUIRE UTILITIES TO FILE A CLASS COST-OF-SERVICE STUDY USING A METHOD OTHER THAN 4CP?

A Yes. The Commission's minimum filing requirements (MFRs) also require filing of a CCOSS using 12CP+8% AD.

Q WHAT IS THE 12CP+8% AD METHOD?

A The 12CP+8% AD method is a composite of two methodologies: (1) 12CP and (2) Average Demand. The 12CP method allocates cost based on each rate class's

[14] Prepared Direct Testimony and Exhibit of Jordan Williams at 25. In his May 22nd deposition, Mr. Williams also referenced TECO's Response to Staff's Sixth Data Request, Request No. 4 provided in the 2021 rate case listing the reasons for adopting 4CP over 12CP. A copy of TECO's Response is provided in **Exhibit JP-3**.

[15] *Id.* at 4.

contribution to each of the 12 monthly peaks during the test year. Average Demand measures each rate class's energy (or kWh) usage throughout the year. Under 12CP+8% AD, 12CP is weighted 92%, while energy usage is weighted 8%.

Q IS THE 12CP METHOD CONSISTENT WITH COST CAUSATION?

A No. 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 placed on the TECO system occurring in the spring and fall months are as critical to system reliability as the summer and winter peak period demands. Thus, by giving substantial weighting to the non-summer months in allocating production and transmission costs, 12CP ignores the reality that TECO's investment in system capacity is driven by its strong summer peaks with a growing winter peak.

Q DOES THE 12CP METHOD BEST REFLECT COST CAUSATION?

A No. The 12CP method overlooks TECO's primary obligation, which is to have sufficient generation capacity to meet the expected system peak demand to ensure that it can provide reliable service to its firm customers. Once installed, the capacity to meet the expected peak demand is also available to meet system demand throughout the year. Thus, meeting system peak demand is the cost-causer, while serving loads in other periods is the *byproduct* of this obligation. Giving equal weight to non-peak months, such as April, dilutes the impact of demands occurring in peak months, such as January and August. TECO must plan for sufficient capacity to meet the expected summer peak (and secondary winter peak) demands if it is to continue providing reliable service to its firm customers. The 12CP method fails to recognize this reality, as well as TECO's own system planning principles.

To illustrate further, if TECO only had to plan for capacity to meet the average of the 12CPs during the (2025) test year, it would have needed only 4,012 MW, plus reserves. If TECO only had 4,012 MW of capacity plus reserves, it would not be able to meet the 4,566 MW peak demand that it is projecting in January 2025 or the 4,366 to 4,421 MW of projected peak demands in June, July and August 2025.[16] In other words, the lights would go out since TECO would have to curtail service to firm customers because it would have insufficient capacity to meet the firm system peak.

Q ARE THERE OTHER AUTHORITIES THAT SUPPORT YOUR OPINION THAT 12CP IS NOT AN APPROPRIATE METHOD FOR TECO?

A Yes. For example, in its Ten-Year Site Plan, TECO measures resource adequacy based on summer and winter peak conditions. Reliability assessments are not conducted for the spring and fall months.

A further example is the National Association of Regulatory Utility Commissioners' cost allocation manual which 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.[17]

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

[16] MFR Schedule E-18.

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

Q HOW IS 12CP+8% AD DIFFERENT FROM 12CP?

A As previously explained, 12CP+8% AD gives weight to both the average of the 12 monthly coincident peak demands and average demand (or annual energy usage). This approach is often referred to as the Peak and Average method.

Q DOES THE PEAK AND AVERAGE METHOD REFLECT COST CAUSATION?

A No. The Peak and Average method does not reflect cost causation.

First, Peak and Average incorrectly assumes that utilities invest in power plants that are more expensive than a combustion turbine (CT) peaking unit to save fuel costs. This is a false notion because, as previously explained, utilities must provide sufficient generation capacity to meet peak demand, which is the cost-causer, while serving load at other times, which is merely the *byproduct* of having enough resource assets to meet peak demand.

Second, Peak and Average ignores that all of the components of the bulk power (*i.e.,* production and transmission) system are operated in a fully integrated manner. For example, solar projects generate electricity only during daytime hours when the sun is shining, while other resources are used to follow the variations in load and supply power when it is needed and cannot be provided by other resources. In other words, because energy from solar projects is intermittent, they cannot be relied upon to provide either firm capacity or firm energy. Thus, solar energy can *temporarily* displace *energy* that would otherwise have been generated from TECO's dispatchable (*i.e.,* coal and gas) generation, but it cannot replace the need for *firm* dispatchable generation *capacity*. Thus, dispatchable generation provides both the necessary firm capacity and firm energy to keep the lights on.

Q ARE THERE OTHER FLAWS WITH THE PEAK AND AVERAGE METHOD?

A Yes. Peak and Average does not allocate fuel costs in a symmetrical manner to production plant costs (*i.e.,* the "fuel symmetry" problem). It also double-counts average demand (*i.e.,* the Double-Counting" problem).

Q WHAT IS THE FUEL SYMMETRY PROBLEM?

A The fuel symmetry problem occurs when production plant is allocated, in part, on an energy basis, but no change is made in how the corresponding fuel costs are allocated. Allocating plant on an energy basis presumes that generating resources with higher installed capital costs – as measured on a per kW basis – are incurred, in part, to save fuel costs rather than to meet peak demand.

For example, combined cycle gas turbine (CCGT) plants have higher installed costs (in $/kW) than CT peaking plants, but CCGTs also have lower fuel costs (on a $/MWh basis) than CTs. Consistency demands that if higher load factor classes are allocated a larger share of CCGT plant costs (because they purportedly benefit more from the lower CCGT fuel costs), they should also be allocated more of the lower CCGT fuel costs. In other words, there should be symmetry between the allocation of fuel costs and the corresponding allocation of capital costs (*i.e.,* a rate class that is allocated more $/kW of capital costs should pay less $/MWh in fuel costs, and vice versa).

Q HAVE OTHER REGULATORY COMMISSIONS CITED THE FUEL SYMMETRY PROBLEM AS A FATAL FLAW WITH THE PEAK AND AVERAGE METHOD?

A Yes. The fuel symmetry problem was one of the primary reasons cited by the Public Utility Commission of Texas in rejecting every type of energy-based allocation method proposed in rate cases throughout the 1980s and 1990s (see, for example, Docket No. 5560; Docket No. 5700; Docket Nos. 7460 and 7172; Docket No. 8032).

For example, in Docket No. 7460, the Commission adopted the Hearing Examiner's Report, which cited the apparent lack of fuel symmetry in rejecting capital substitution, an energy-based allocation method.

> The Examiner's 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 the 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.[18]

Q WOULD THE FUTURE SOLAR PROJECTS TECO IS PROPOSING BE AN EXCEPTION BECAUSE THEY ARE BEING INSTALLED TO LOWER FUEL COSTS?

A No. TECO is partially cost-justifying the Future Solar Projects based on their ability to reduce fuel costs. However, the primary driver to install solar (rather than fossil fuel) plants is clearly public policy – primarily to reduce carbon emissions. As discussed in Mr. Ly's testimony, the cost-effectiveness of TECO's Future Solar Projects is largely a result of the PTCs for which they are eligible. Discounting the impact of these PTCs, the net benefits of these resources would be severely diminished. Therefore, the fuel savings alone would not justify the much higher installed cost.

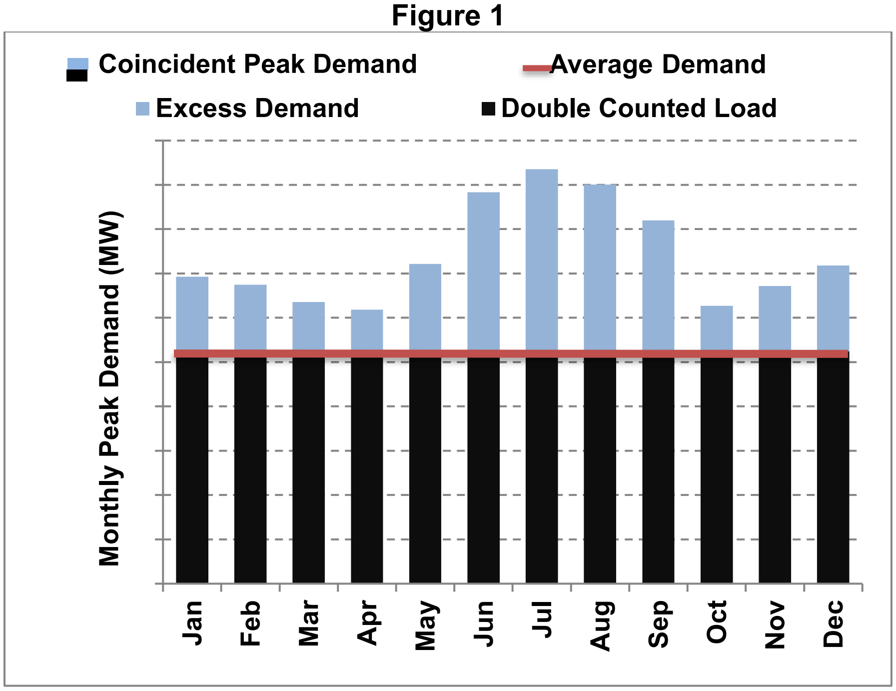
[18] *Application of El Paso Electric Company for Authority to Change Rates and Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit 2*, Consolidated Docket Nos. 7460 and 7172, Examiner's Report, at 199 (Jun. 16, 1988), adopted in *Order on Rehearing* (May 10, 1988), 14 Tex. P.U.C. Bull. 929.

However, notwithstanding the integrated nature of TECO's generation fleet, if the proposed Future Solar Projects are to be allocated using a methodology other than 4CP, the costs should be allocated to the periods the solar plants are expected to produce energy (*i.e.,* daytime hours) and not spread to all hours.

Q WHAT IS THE DOUBLE-COUNTING PROBLEM?

A Double-counting can occur when plant-related costs are properly allocated partially on a coincident peak basis and 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 the following Figure 1 for a hypothetical summer peaking utility.

Figure 1



Average demand is equivalent to the black shaded area of the chart. Coincident peak demand is represented by the combined black and blue shaded areas. Double-counting occurs because coincident peak demand incorporates average demand.

By allocating some plant-related costs relative to average demand and some relative to coincident peak demand, energy usage is counted twice in the allocation process: once by itself and a second time as a subset of coincident peak demand. If you presume that base load units are built to meet average year-round demand, then it follows that the only time load-following (*e.g.*, intermediate and peaking) units would be needed is when system demands exceed the average demand. The proponents of the Peak and Average method would allocate the cost of this additional capacity relative to coincident peak demand (*i.e.*, the entire bar including both the black and blue portions of the bars), rather than just the excess demand (*i.e.*, the blue portion of the bar).

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLOW IN ENERGY-BASED PEAK AND AVERAGE ALLOCATION METHODOLOGIES?

A Yes. For example, the Public Utility Commission of Texas cited the double-counting problem in numerous cases. For example:

> 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 4CP 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.[19]

[19] *Id.* at 199.

Q YOU PREVIOUSLY DISCUSSED HOW TECO'S GENERATION FLEET IS FULLY INTEGRATED. DOES THE INTEGRATED NATURE OF THE GENERATION FLEET SIMILARLY APPLY TO THE INDIVIDUAL COMPONENTS OF TECO'S DISPATCHABLE GENERATING PLANTS?

A Yes. For example, TECO proposes to classify the cost of the gasifier investment at Polk 1 and the scrubber at Big Bend Unit 4 as energy-related costs. However, this is apportioning parts of a generation plant as if the generation plant can function in pieces. If a generator needs all pieces to deliver firm capacity and energy, then all pieces of the generator should be classified the same. Accordingly, since no generator can provide firm capacity and energy without a reliable fuel source (*i.e.,* the Polk 1 gasifier) or, in the case of Big Bend Unit 4, absent the scrubber, there is no valid reason to classify the Polk 1 gasifier and Big Bend Unit 4 scrubber differently than the remaining investments in these plants.

Q WHAT DO YOU RECOMMEND?

A The Commission should, once again, approve the 4CP method to allocate production and transmission plant and related costs. The Commission should reject the 12CP method for retail class allocation because it is contrary to both cost causation and the reality that TECO has had (and is expecting to continue having) well defined seasonal (summer and winter) peaks.

<u>Minimum Distribution System</u>

Q EARLIER YOU STATED A PREFERENCE FOR TECO'S MDS METHODOLOGY. WHY SHOULD TECO'S MDS BE USED FOR SETTING RATES IN THIS PROCEEDING?

A The MDS classifies a portion of the distribution network as a customer-related cost. This is in stark contrast to the 12CP+8% AD CCOSS in which all distribution network costs are considered demand related. 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.

Q WHAT ARE DISTRIBUTION NETWORK COSTS?

A The electric distribution network consists of TECO'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 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).

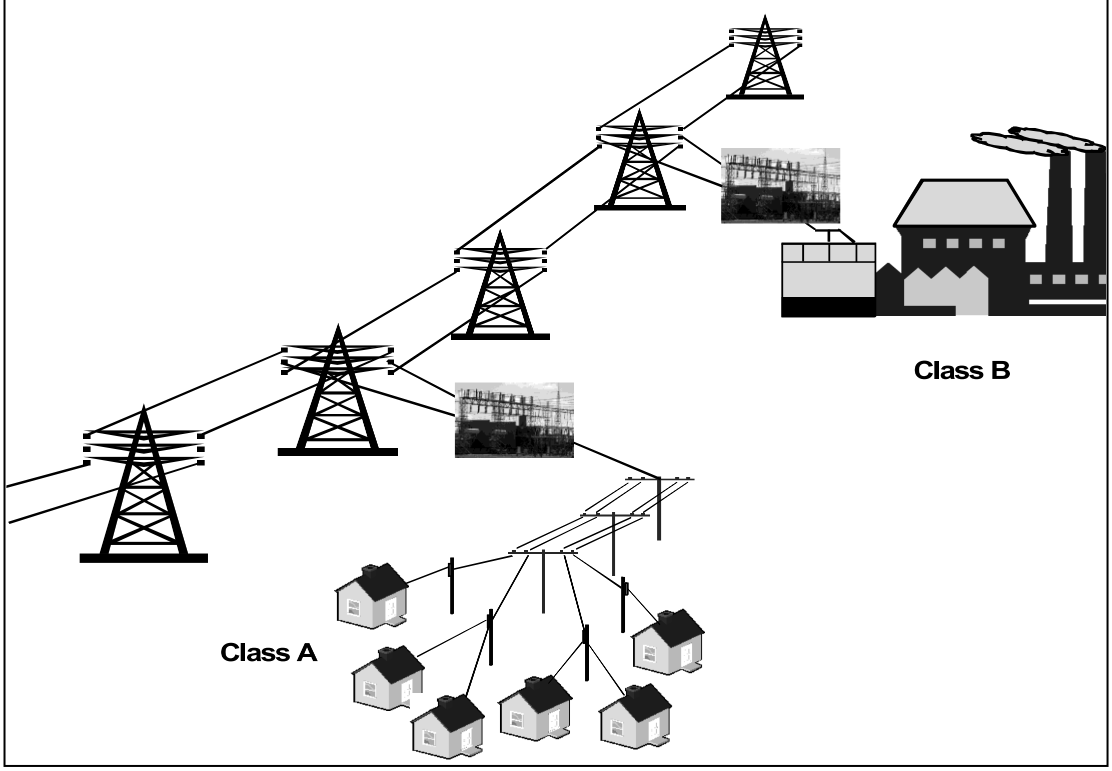
Providing access to a safe, delivery-ready power grid requires not only a physical connection that meets all construction and safety standards, but also the voltage support and readiness to serve, which is provided by the distribution network infrastructure. Clearly, these costs are related to the existence 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 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 the 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.

If TECO 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



In this example the physical distribution network necessary to attach Class A, a residential subdivision, 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:

> 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.[20]

Q WHAT DO YOU RECOMMEND?

A The Commission should approve the MDS in setting base rates in this proceeding. The MDS methodology more fairly allocates costs between user groups and recognizes that there are additional customer-related costs to provide distribution service (other than the meter and service drop). Further, it allocates these costs based on the number of customers, which is consistent with cost causation. MDS is an accepted industry practice which the Commission has previously approved for use with Gulf Power and TECO.

Revised CCOSS

Q HAVE YOU REVISED TECO'S 4CP/MDS CCOSS?

A Yes. A revised 4CP/MDS CCOSS is provided in **Exhibit JP-4.** As discussed earlier, TECO allocated the vast majority of the PTCs to rate classes using the 4CP method. PTCs are earned for every MWh generated from TECO's owned solar projects. Thus, allocating PTCs on an energy basis would better reflect cost causation than TECO's proposed 4CP method. Additionally, I have classified the Polk 1 gasifier and Big Bend Unit 4 scrubber as demand-related costs.

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

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 TECO 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 will, in turn, minimize the costs to the utility; they enhance revenue stability because an increase or decrease in sales and revenues would be offset by an increase or decrease in expenses, thus keeping net income stable; 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 TECO's five separate cost recovery mechanisms:

- Fuel and Purchased Power;
- Energy Conservation;
- Environmental;
- Storm Protection; and
- Clean Energy Transition Mechanism.

With the exception of the Clean Energy Transition Mechanism, the costs recovered in these cost recovery mechanisms are not subject to change in a base rate case. Further, gradualism is not considered in any of the other cost-recovery mechanisms. Therefore, a general rate case is the only venue in which gradualism can be properly applied.

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

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

A Yes. **Exhibit JP-5** uses TECO's 4CP/MDS CCOSS with the corrections discussed previously. My recommendation would result in moving all rate classes, except Lighting, to a relative rate of return of 0.98, which is just slightly below parity. Consistent with gradualism, the Lighting class would receive no increase because it is already providing a rate of return that exceeds TECO's proposed system average rate of return, and no class would receive a base revenue increase higher than 1.5 times the 19.8% system average base revenue increase.

5. RATE DESIGN

Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I address TECO's proposals to eliminate seasonal rates and to implement a Super Off-Peak period that would set very low energy prices during the majority of the daytime hours throughout the year.

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.

Q WHY IS TECO PROPOSING TO ELIMINATE SEASONAL RATES?

A TECO believes that, although there are seasonal components to its peaks, eliminating seasonal rates would achieve simplicity and understandability, thereby making it easier for customers to set their operations year-round.[21]

Q WOULD ELIMINATING SEASONAL RATES BE CONSISTENT WITH COST CAUSATION?

A No. As previously discussed, TECO supports the 4CP method of allocating production and transmission plant and related expenses. The 4CP method recognizes that TECO experiences its peak demands for electricity (which determine the amount of generation capacity required to maintain reliable service) during the summer months (June, July, and August) while also recognizing a growing winter peak (January).

[21] Prepared Direct Testimony and Exhibit of Jordan Williams at 32.

There is no clear connection or rationale between TECO's CCOSS and a seasonal rate design.

Q SHOULD A DESIRE FOR SIMPLICITY AND TO MAKE IT EASIER FOR CUSTOMERS TO SET THEIR OPERATIONS YEAR-ROUND OVERRIDE A RATE DESIGN THAT IS CLEARLY FOUNDED ON COST CAUSATION?

A No. TECO has had seasonal rates for many years. Not only would eliminating seasonal rates not be consistent with cost causation, it would actually make customers' lives *less* simple. When coupled with the introduction of low Super Off-Peak energy charges during daytime hours, it will force customers to change long-established operating practices. Both rate design changes are far from gradual, and as discussed later, they are premature.

Q WHY IS IT IMPORTANT TO DESIGN RATES THAT REFLECT COST?

A As with class revenue allocation, a cost-based rate design is fair because each customer will pay rates that reflect the customer's cost to serve, as closely as practicable. Similarly, a cost-based rate design is also efficient, will encourage conservation, and provide a more stable revenue stream. This is because a cost-based rate design will send the price signals that incent customers to minimize their costs which will, in turn, minimize TECO's costs.

Q HOW IS TECO PROPOSING TO REDEFINE THE TIME-OF-DAY RATING PERIODS?

A The changes in time-of-day definitions are summarized in Table 2.

Table 2
Time of Day Periods

Period	Current		Proposed Year-Round
	Apr-Oct	Nov-Mar	
Peak*	Mon-Fri 12 p.m. -9 p.m.	Mon-Fri 6 a.m. -10 a.m. 6 p.m. – 10 p.m.	Mon-Fri 6 a.m. – 10 a.m. 5 p.m. – 9 p.m.
Off-Peak	All else	All else	All else
Super Off-Peak	N/A	N/A	Mon-Sun 10 a.m.- 5 p.m.

* Excluding Holidays
Source: Direct Testimony of Jordan Williams at 29-31

The most significant change would be to establish a new Super Off-Peak period between the hours of 10 a.m. and 5 p.m. daily, including weekends. The base energy charges during Super Off-Peak hours would be lower than the corresponding charges in both Peak and Off-Peak hours. As Table 2 demonstrates, the proposed Super Off-Peak period would largely overlap the current April to October (summer) peak hours, which occur between 12 p.m. and 9 p.m.

The proposed On-Peak hours, by contrast, would include morning hours between 6 a.m. and 10 a.m. year-round. Currently, these hours are On-Peak during the November to March (winter) period. Under TECO's proposal, the evening On-Peak hours during the summer afternoons would not commence until 5 p.m. Thus, the vast majority of the daytime hours that are now considered On-Peak with higher prices than during Off-Peak hours, would become the lowest price Super Off-Peak hours. This is a dramatic change. Further, it will require customers to make drastic operational changes.

Q WHAT IS THE BASIS FOR TECO'S PROPOSED SUPER OFF-PEAK PRICING?

A TECO states that it used a marginal cost methodology to determine the time-of-use rating periods and rate differentials. Specifically, TECO states that future marginal costs are being impacted by the continued integration and growth in renewable generation.[22]

Q ARE THE MARGINAL ENERGY PRICES CONSISTENTLY LOW DURING THE PROPOSED SUPER OFF-PEAK PERIOD?

A No. **Exhibit JP-6** is a heat map showing the average marginal energy costs by hour by month. The Super Off-Peak hours are highlighted in yellow, and the corresponding marginal energy costs are within the black border. The higher price hours are indicated in red, while the lower price hours are indicated in green. As can be seen, with the exception of April and May, the marginal energy costs are not consistently low during TECO's proposed Super Off-Peak period.

Q EVEN IF MARGINAL ENERGY COSTS WERE CONSISTENTLY LOW DURING SUPER OFF-PEAK HOURS, WOULD IT BE REASONABLE TO PRICE ENERGY LOWER DURING DAYTIME HOURS SOLELY DUE TO HIGHER SOLAR PENETRATION?

A No. The decision to invest in ever increasing amounts of solar will result in a "duck curve." A duck curve occurs when uncontrollable generation like solar decouples cost from load on the grid. In effect, during high load conditions, pricing appears low and it creates a perverse incentive to use more energy during high load conditions. Not only

[22] *Id*. at 31.

does this contradict many years of encouraging customers to conserve energy during peak periods, the duck curve has also resulted in significant challenges for grid operators. In a recent posting by the U.S. Energy Information Administration:

> The duck curve presents two challenges related to increasing solar energy adoption. The first challenge is grid stress. The extreme swing in demand for electricity from conventional power plants from midday to late evenings, when energy demand is still high but solar generation has dropped off, means that conventional power plants (such as natural gas-fired plants) must quickly ramp up electricity production to meet consumer demand. That rapid ramp up makes it more difficult for grid operators to match grid supply (the power they are generating) with grid demand in real time. In addition, if more solar power is produced than the grid can use, operators might have to curtail solar power to prevent overgeneration. [23]

Q ARE MARGINAL ENERGY COSTS THE ONLY CONSIDERATION IN DETERMINING TIME-OF-USE RATING PERIODS AND PRICING DIFFERENTIALS?

A No. Time-of-use rating periods should also consider other factors besides marginal energy costs. These factors include system loads, loss of load expectation, and the fact that TECO has to maintain dispatchable generation capacity to support the integration of renewable resources to ensure that supply and demand remain in balance from minute-to-minute. As more renewable generation is integrated into the system, resulting in an even steeper duck curve, the more stress will be imposed on TECO's dispatchable generation, resulting in higher (fuel and maintenance) costs and shorter operating lives.

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[23] As solar capacity grows, duck curves are getting deeper in California - U.S. Energy Information Administration (EIA).

Q SHOULD THE COMMISSION APPROVE TECO'S PROPOSED SUPER OFF-PEAK PERIOD?

A No. The proposal would be a very dramatic and drastic change in pricing. It would require customers to significantly change their operations to adapt to the proposed changes.

Second, as previously stated, low energy prices during daytime hours sends the wrong price signals because peak demands occur during daytime hours.

Third, it is premature to premise a major rate structure change on TECO's ever-expanding investment in renewable generating assets. Mr. Ly has determined that the cost-effectiveness analysis supporting the proposed Future Solar Projects is insufficiently robust, and therefore, these projects should only be approved if the Commission Orders a construction cost cap and operating performance guarantees.

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:

- Adopt a lower ROE that reflects TECO's reduced regulatory lag and financial risk.
- Adopt the 4CP method of allocating production and transmission plant.
- Reject TECO's proposal to classify the Polk 1 gasifier and Big Bend Unit 4 scrubber as energy costs.
- Adopt TECO's Minimum Distribution System methodology in allocating distribution network costs.
- Allocate production tax credits on an energy basis.
- Reject TECO's proposals to eliminate seasonal rates and to establish a Super Off-Peak period during all daytime hours.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

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 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, 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.

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	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
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

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Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

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Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

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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
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

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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
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

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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
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

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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
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

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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
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

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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.

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.

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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI** **Filed: June 6, 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. 20240026-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 6th 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.

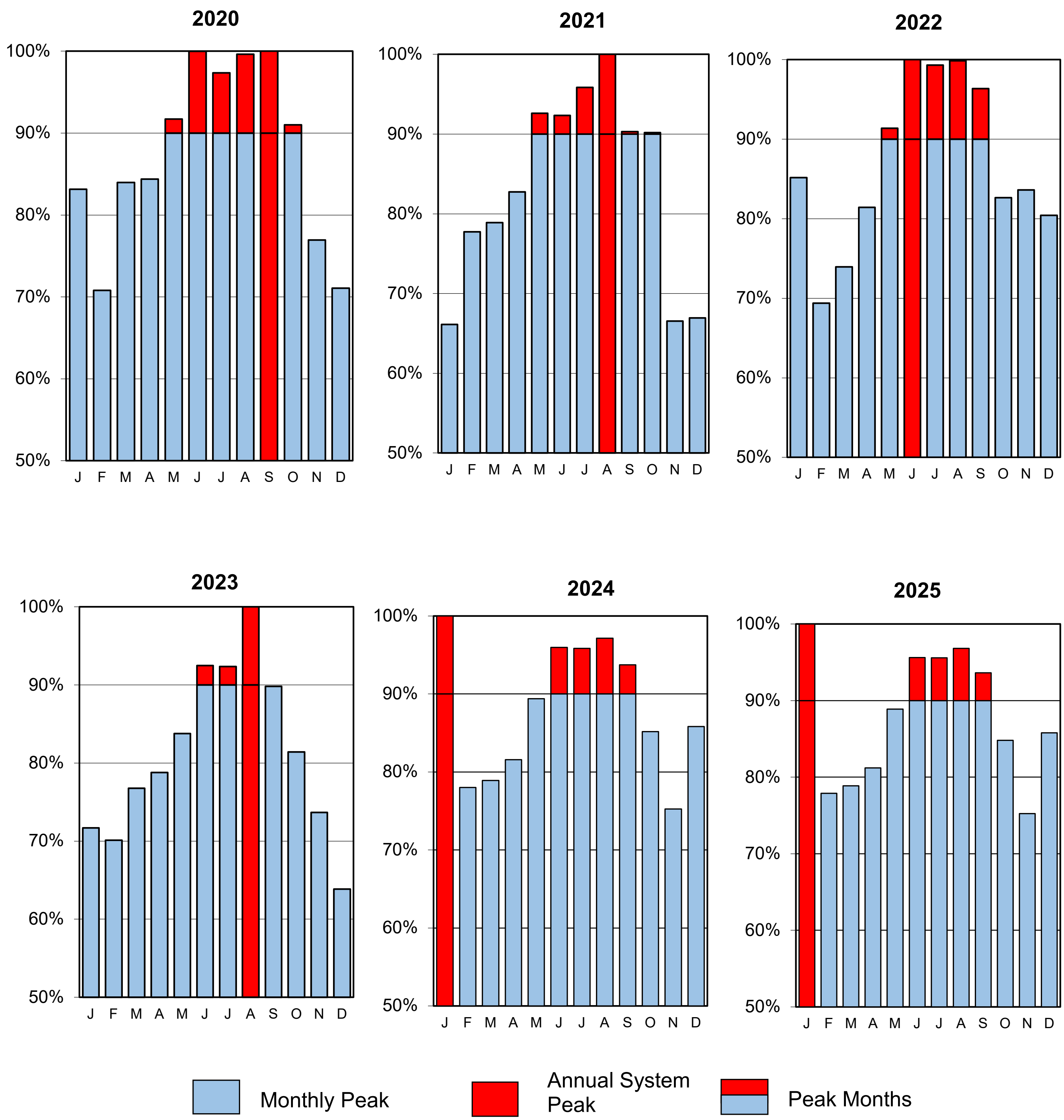
Authorized Return On Equity For Vertically Integrated Electric Utilities
In Rate Cases Decided in 2023 and 2024

Line	*State*	*Company*	*Docket*	*Date Decided*	*Return on Equity (%)*
1	Michigan	Consumers Energy Co.	C-U-21224	1/19/2023	9.90
2	Minnesota	Minnesota Power Entrprs Inc.	D-E-015/GR-21-335	1/23/2023	9.65
3	Wyoming	Cheyenne Light Fuel Power Co.	D-20003-214-ER-22	1/26/2023	9.75
4	South Carolina	Duke Energy Progress LLC	D-2022-254-E	2/9/2023	9.60
5	Louisiana	Southwestern Electric Power Co	D-U-35441	2/17/2023	9.50
7	Michigan	Upper Peninsula Power Co.	C-U-21286	3/24/2023	9.90
8	California	Liberty Utilities (CalPeco Ele	A-21-05-017	4/27/2023	10.00
9	Minnesota	Northern States Power Co.	D-E-002/GR-21-630	6/1/2023	9.25
10	North Dakota	MDU Resources Group	C-PU-22-194	6/6/2023	9.75
11	Indiana	Northern IN Public Svc Co. LLC	Ca-45772	8/2/2023	9.80
12	Texas	Entergy Texas Inc.	D-53719	8/3/2023	9.57
13	North Carolina	Duke Energy Progress LLC	D-E-2 Sub 1300	8/18/2023	9.80
14	Vermont	Green Mountain Power Corp.	C-23-1852-TF	8/23/2023	9.58
15	Arizona	Tucson Electric Power Co.	D-E-01933A-22-0107	8/25/2023	9.55
16	Alaska	Alaska Electric Light Power	D-U-22-078	8/31/2023	11.45
17	Idaho	Avista Corp.	C-AVU-E-23-01	8/31/2023	9.40
18	Colorado	Public Service Co. of CO	D-22AL-0530E	9/6/2023	9.30
19	Montana	MDU Resources Group	D-2022-11-099	9/21/2023	9.65
20	Kentucky	Duke Energy Kentucky Inc.	C-2022-00372	10/12/2023	9.75
21	New Mexico	Southwestern Public Svc Co.	C-22-00286-UT	10/19/2023	9.50
22	Montana	NorthWestern Energy Group	D-2022-7-78 (elec)	10/25/2023	9.65
23	Oklahoma	Public Service Co. of OK	Ca-PUD2022-000093	11/3/2023	9.30
24	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-125 (Elec)	11/3/2023	9.70
25	Wisconsin	Northern States Power Co.	D-4220-UR-126 (Elec)	11/9/2023	9.80
26	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-124 (Elec)	11/9/2023	9.80
30	Wyoming	PacifiCorp	D-20000-633-ER-23	11/28/2023	9.35
31	Michigan	DTE Electric Co.	C-U-21297	12/1/2023	9.90
33	Arkansas	The Empire District Electric C	D-22-085-U	12/7/2023	9.70
34	California	PacifiCorp	A-22-05-006	12/14/2023	10.00
35	North Carolina	Duke Energy Carolinas LLC	D-E-7 Sub 1276	12/15/2023	10.10
36	Oregon	Portland General Electric Co.	D-UE-416	12/18/2023	9.50
37	California	Pacific Gas and Electric Co.	Advice 4813-G/7046-E	12/22/2023	10.70
38	California	San Diego Gas & Electric Co.	Advice Letter 4300-E / 3239-G	12/22/2023	10.65
39	California	Southern California Edison Co.	Advice Letter 5120-E (U 338-E)	12/22/2023	10.75
40	Nevada	Nevada Power Co.	D-23-06007	12/26/2023	9.52
41	Idaho	Idaho Power Co.	C-IPC-E-23-11	12/28/2023	9.60

Authorized Return On Equity For Vertically Integrated Electric Utilities
In Rate Cases Decided in 2023 and 2024

Line	*State*	*Company*	*Docket*	*Date Decided*	*Return on Equity (%)*
42	New Mexico	Public Service Co. of NM	C-22-00270-UT	1/3/2024	9.26
43	Kentucky	Kentucky Power Co.	C-2023-00159	1/19/2024	9.75
44	Arizona	UNS Electric Inc.	D-E-04204A-22-0251	1/30/2024	9.75
45	Virginia	Virginia Electric & Power Co.	C-PUR-2023-00101	2/28/2024	9.70
46	Michigan	Consumers Energy Co.	C-U-21389	3/1/2024	9.90
47	Arizona	Arizona Public Service Co.	D-E-01345A-22-0144	3/5/2024	9.55
50	West Virginia	Monongahela Power Co.	C-23-0460-E-42T	3/26/2024	9.80
51	Indiana	AES Indiana	Ca-45911	4/17/2024	9.90
52	Indiana	Indiana Michigan Power Co.	Ca-45933	5/8/2024	9.85
53	**Average for 2023**				**9.80**
54	**Average for 2024**				**9.72**
55	**Average for 2023 through May 2024**				**9.78**

Tampa Electric Company
Monthly Peak Demands as a Percent of the Annual System Peak Demand
<u>for the Years 2020 through 2025</u>



TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
STAFF'S SIXTH DATA REQUEST
REQUEST NO. 4
BATES PAGES: 12 - 21
FILED: SEPTEMBER 7, 2021

4. Referring to paragraph 6(d) of the Settlement, and the use of the 4 Coincident Peak (CP) methodology for allocating production and transmission plant, please respond to the following questions:

a. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP and 1/13 Average Demand (AD) methodology for production as included in the original MFRs.

b. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP methodology for transmission as included in the original MFRs.

c. State which three summer and which one winter month are being used to allocate production and transmission costs and explain why those particular months were chosen.

d. Discuss whether TECO designs and provides generation and transmission capacity needs for twelve months of the year or just four months of the year.

e. Are transmission costs to wholesale customers allocated on a 12 CP or 4 CP methodology? If on a 12 CP methodology, wouldn't the proposed 4 CP methodology create a mismatch between the retail and wholesale jurisdiction?

f. Discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed 4 CP methodology (when compared to the methodology used in the MFRs), by shifting target revenue requirements to the rate class away from other rate classes.

g. Discuss why the Settlement includes a provision that in the next general base rate proceeding, the filed cost-of-service study will use the 4 CP cost allocation.

h. Clarify whether in the next general base rate proceeding, TECO will only include the 4 CP cost of service methodology, or the 4CP and 12 CP and 1/13 AD methodology.

i. Explain who are the "Precluded Parties" and why would an affiliate of TECO oppose the 4 CP and full MDS.

4a. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP and 1/13 Average Demand (AD) methodology for production as included in the original MFRs.

A. Three preliminary points are important.

First, the cost allocation methodology that the Parties unanimously agreed upon in the 2021 Agreement was and is recognized by the Parties as reflecting cost-causation on Tampa Electric's system and as reasonable for ratemaking purposes.

Second, although the 4 CP and Full MDS methodologies were used as the starting point to guide revenue allocation and rate design in the 2021 Agreement, the Parties agreed to specific rate class revenue allocations to substantially mitigate the impact of fully applying the new methodology in this case. The agreed-to revenue allocations were used with billing determinants to develop the agreed-to rates, which were reflected in the company's updated tariffs that were filed on August 20, 2021.

Third, use of the 4 CP methodology as reflected in the 2021 Agreement is best understood as part of the settlement as a whole, in light of the reasons the 12 CP and 1/13th methodology was adopted in the 1980s (which reflected key factors that determined Tampa Electric's past investments in production, transmission, and distribution plant), and in light of the fundamental theme of this rate case, namely transformation. The part of the company's transformation relevant for cost-of service purposes is the company's transition from a generation fleet dominated by baseload coal generation in the early 1980s to its current fleet that is predominantly natural gas and some solar generation with very limited coal, to a future system that over time is planned to include solar, storage, some gas, and other low-or-no-carbon fuels.

<u>The Overall Settlement</u>
Almost every settlement agreement considered and approved by the Commission reflects give and take among the parties and reflects an integrated package of exchanged agreements and consideration. The answer to why any particular provision was included in a settlement always boils down to a simple answer, namely, because the parties, notwithstanding their diverse and often competing interests, agreed to it. In virtually every settlement, every party likely would have objected to some feature(s) of the settlement if offered individually and not as a part of a larger integrated package, but nonetheless agreed to settlement in its totality. The 2021 Agreement is no different in this regard.

Adoption of 12 CP and 1/13th Methodology

The 12 CP and 1/13th cost-of-service methodology has been in use for approximately 40 years and was approved for Tampa Electric as early as its 1982 rate case. See Order No. 11307, Docket No. 19820007-EU, issued November 11, 1982. That order noted: "We continue to believe that the 12 CP and one - thirteenth weighted average method is the best demand allocation methodology to use in Florida. This is so because each monthly peak is important in TECO's system planning perspective when periods of peak demands and the necessary periods of planned outages are considered."

The 12 CP and 1/13th methodology was found appropriate in part because of the weather and the weather's impact, in that era, on production plant operations and expansion. At the time, Florida utilities had periods of substantial summer load (driven primarily by air conditioning) that extended from May through September that required peaking coverage but depended on long and sustained energy production from mid-morning to late evening using baseload, coal-fired generating units.

Significant winter peaks occurred sporadically between December and March when arctic cold fronts reached Florida bringing temperatures below 30 degrees. During these brief periods of cold temperatures usually occurred in the mornings when customers (primarily residential) relied on resistive heating (strip heat) or the strip heating elements of heat pumps to warm their homes, thereby creating brief periods of high demand that often exceeded the summer peak load, but usually only for a couple of hours.

The remaining shoulder months (April, May, October, and November) were considered important months for meeting peaks because of the heavy reliance on coal generating plants, which in those months were often out of service for planned maintenance and thus were not available to meet cooling-driven peak loads that occurred sporadically and infrequently in those months.

The 1/13th element of the methodology (later 25 percent) was added in part to allocate some production plant to non-firm load that was not allocated production costs for recovery in their base rates but benefitted in lower fuel cost from the coal plants that served their load.

Transformation Since the 1980s

The reasoning and arguments in favor of the 4 CP methodology considered by the Parties when negotiating the 2021 Agreement reflect the ongoing evolution of the company's generating fleet in the context of significant, even dramatic, advances in generating technology, equally important changes in energy policy, and the company's changing demand profile, all of which are part of the the fundamental theme of this proceeding, namely transformation.

From the beginning, this rate case has been about the changing energy industry, the transformation of Tampa Electric and positioning the company for a future in which renewable energy, clean energy, carbon reduction, conservation, and distributed generation will be more important.

Tampa Electric is different than it was during its 2013 rate case, and far different than it was in the early 1980s when the 12 CP and 1/13th cost-of-service methodology was approved.

In the early 1980s, the company's generating fleet was dominated by large, base-load coal-fired generating units; reduction of carbon emissions was not a major policy goal; and the Commission's efforts to promote demand-side management (energy conservation) were just beginning.

Ninety-nine percent of the company's electricity was generated using coal in 1985.

By 2013, about 59 percent of Tampa Electric's electricity was generated using coal, about 41 percent was natural gas-fired, and the company had no solar generation.

By 2020, about five percent of its electricity was generated using coal, about 89 percent was natural gas-fired, and about 6 percent was from solar.

As part of this case and as reflected in the 2021 Agreement, the company has retired three of the four coal units at Big Bend Station and the fourth runs primarily on natural gas.

With the addition of the 600 MW of Future Solar facilitated by the 2021 Agreement, nearly 14 percent of the company's energy production will be from solar by 2025, which will be enough to power more than 200,000 homes.

The company's investments in solar generation make it a leader in solar energy, promote price stability for customers, increase its fuel diversity, and contribute to the reduction of carbon emissions.

The company's generation mix changes have significantly reduced its carbon emissions, which fell from 15.7 million tons in 2013 to about 8.8 million tons in 2020. By 2023, the company expects to have reduced its carbon dioxide emissions by the equivalent of removing one million cars from local roadways.

Since the early 1980s, the company's FPSC-approved DSM programs have reduced the need of 779 MW of summer peak demand, 1,289 MW of winter peak demand, and 1,722 GWh of annual energy. These demand and energy reductions have eliminated the need for seven – 180 MW peaking power plants along with the significant savings on fuel usage and emissions. The value of interruptible customers and demand response is now reflected in the company's Commission-approved conservation programs and the CCV credit.

The company's investment in Advanced Metering Infrastructure (AMI), also facilitated by the 2021 Agreement, will pave the way for the company to empower customers through technology via a smarter grid that delivers safe, more reliable, and affordable energy, and that will enable the company to accommodate larger amounts of company-owned and customer-owned distributed generation (including roof-top solar) and to offer enhanced demand response and other conservation programs.

The company's most recent Ten-Year Site Plan portends a future built primarily around battery storage and additional utility-scale solar, not large fossil fuel-fired generating stations. This future looks nothing like the 1980s and invites a fresh look and innovation in the cost-of-service methodology area.

Arguments for 4 CP

While there was lively and thoughtful discussion of the specifics of cost-of-service approaches during the settlement process, there was a shared belief among the Parties that movement toward a summer/winter approach with all production and transmission costs classified as demand-related would better reflect cost causation for Tampa Electric as it prepares for a future built on more solar, renewable and clean energy, and a greater emphasis on carbon reduction, conservation, and distributed generation. Notably, Tampa Electric proposed using a new summer/winter allocation methodology to be applied to its new solar production assets in its original filing.

Some of the ideas considered by the Parties as part of the settlement process included:

1. A cost-of-service study is an analysis used to determine each rate class's responsibility for a utility's costs, so it influences the revenues a rate class generates to cover a class's cost of service. How cost is defined, which cost-of-service methodology is appropriate and how costs are allocated during the preparation of a cost-of-service study are issues over which reasonable people can differ.

2. As the company has retired its coal plants, the importance of the shoulder months for base load coal-plant planned outages and cost attribution has diminished. The notion inherent in the 12 CP and 1/13th methodology that each monthly coincident peak should be given the same importance for cost-of-service purposes seems less applicable now than it was in the coal-dominated early 1980s.

3. Although Tampa Electric was once a consistently winter peaking utility, that has changed, in part because energy efficiency and conservation programs have improved energy efficiency, reduced customer reliance on resistive strip heating, and because recent winters have been milder, which trend is not reasonably expected to reverse. The company's most recent Ten-Year Site Plans show 3 of 4 annual peak periods occurring in the summer cooling season. Although it had not happened by the time the 2021 Agreement was filed, Tampa Electric recently experienced a new, all-time summer peak demand of 4,514 MW on August 18, 2021.

4. Recent history suggests that global climate change appears to be bringing hotter summers and milder winters to Florida. These changes will elevate the summer months' importance for operational planning and cost attribution purposes. Conversely, the increased reliance of solar to meet peak will increase the need to have alternative supply resources to meet the less frequent but still important winter peaks.

5. Although the company must plan for every month (indeed all 8,760 hours each year), its operational planning currently focuses on meeting both the heavy summer cooling months and the possibility of an occasional cold snap in the winter. The transition to a 4 CP methodology in the 2021 Agreement reflects a greater emphasis on the heavy summer cooling months and an occasional cold winter month. The company's recent new summer peak in August reinforces this idea.

6. Tampa Electric's Ten-Year Site Plan focuses on two system peaks for calculating reserve margin: a summer and a winter peak, and this consideration alone could support a 2CP methodology. By emphasizing the four most important monthly coincident peaks in a year, the 4 CP methodology with future innovative rate design ideas will over time move rates closer towards Tampa Electric's planning parameters, and associated cost causation, for peak demand capacity, including reserve margins, and will encourage use of the system's assets when they would be otherwise underutilized, shifting demand away from peak periods. While the Site Plan focuses on two peaks, the 2021 Agreement instead looks to 4 CP, a middle

ground between the historical 12 CP and the summer and winter peak focus implicit in the Ten-Year Site Plan.

7. The industrial and large commercial customers on Tampa Electric's system tend to be high-load factor customers consistently on a year-round basis, while residential (RS) and small commercial customers (GS) tend to be very "peaky" due to their demand for summer cooling (air conditioning) and occasional winter heating (resistive strip). Indeed, it is generally recognized that residential cooling and heating drive system peaks for utilities in the southeastern United States.

8. The manner in which the 4 CP methodology allocates costs to the RS class may incent RS customers to install additional customer-sited solar, which would lead to more clean energy overall and will become more important for achieving global, national, and company-specific carbon reduction goals. Tampa Electric believes that additional customer-sited solar, updating the rules governing customer-sited solar, and new optional programs will be part of an overall strategy for reducing carbon emissions in the future.

9. Among other things, the Tampa area currently is home to steel, construction materials, furniture, electronics, and disinfectant manufacturing facilities that employ many people. Over time, application of a 4 CP cost-of-service methodology may make manufacturers and other large employers in Tampa Electric's service territory more competitive vis-à-vis other competing regions, including those that use 4 CP or a derivative thereof. The 4 CP method or variants thereof are used in Texas, Colorado, New Mexico, Oklahoma, and Arkansas, and other jurisdictions consider 4 CP as a tool to attract businesses and jobs.

10. The 12 CP methodology, which equally values all 12 monthly coincident peaks, does not attribute the costs of solar generation to customer classes as efficiently as the 4 CP methodology. Solar PV panels are intermittent resources that generate electricity whenever the sun is shining and have zero fuel costs relative to other resources in the order of dispatch. Solar will be in place and producing energy every day of the year – including shoulder months when there may be more solar power than needed to economically meet demand. The 4 CP methodology can be viewed as a platform for future innovative pricing approaches that will more closely align incremental costs and revenues.

4b. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP methodology for transmission as included in the original MFRs.

A. As was the case for generation, the Parties agreed to the 4 CP methodology in the 2021 Agreement for transmission investment, subject to mitigation in the class revenue allocation process, as part of the overall settlement. In addition to the general considerations described above, fixed demand related costs, such as the return on transmission plant investment and fixed transmission O&M, are incurred by a utility to meet the peak demand of its customers. Once transmission investment has been constructed, their demand-related costs are fixed and do not vary with the amount of energy they carry. As a result, economic efficiency is achieved by allocating fixed demand related costs on the basis of class peak demand.

4c. State which three summer and which one winter month are being used to allocate production and transmission costs and explain why those particular months were chosen.

A. The Parties agreed to use June, July, August, and January for the 4 CP methodology employed in the 2021 Agreement. These are the four months in which peak demand was projected to be above 4,000 MW in the company's most recent Ten-Year Site Plan. Each of these months exceed 90 percent of the company's system peak demand, whereas no other month does. As noted above, Tampa Electric recently experienced a new, all-time summer peak demand of 4,514 MW on August 18, 2021.

4d. Discuss whether TECO designs and provides generation and transmission capacity needs for twelve months of the year or just four months of the year.

A. Like other utilities, Tampa Electric must be ready to provide electricity instantaneously 24 hours a day and 365 days a year, not just once a month for 12 months or once a month for four months. However, in planning to meet system demand requirements, Tampa Electric's Ten-Year Site Plans rely on a single "Winter Peak" and a single "Summer Peak" in its projections of CP demand for determining the load and resource balances explained in the response to Request 4a, above, the company's transformation away from large, baseload, coal-fired generating units and to cleaner generating resources like solar has diminished the importance of the shoulder months for operational planning and cost attribution purposes, so it is reasonable to move away from a cost-of-service methodology that values each monthly peak in a 12-month period equally. Ultimately, Tampa Electric must build sufficient capacity (both generation and transmission) to meet its projected peak demands, with a sufficient reserve margin to ensure reliability; because Tampa Electric experiences peaks in both the summer and the winter, Tampa Electric must plan for both. Having said that, once the capacity to meet the peak is constructed, it is available to meet all demands that occur during the year, so it is appropriate to allocate costs on the basis of the critical summer and winter peaks that drive Tampa Electric's planning and investment decisions.

4e. Are transmission costs to wholesale customers allocated on a 12 CP or 4 CP methodology? If on a 12 CP methodology, wouldn't the proposed 4 CP methodology create a mismatch between the retail and wholesale jurisdiction?

A. As specified in Paragraph 6(b)(iii) of the 2021 Agreement, retail transmission costs will be allocated to rate classes using 4 CP as mitigated. Tampa Electric's current Open Access Transmission Tariff rates uses a formula that applies a 12 CP allocation; however, Tampa Electric currently has no long-term wholesale power customers, either full or partial requirements based. In addition, Tampa Electric does not currently have any retail transmission only customers. Consequently, there is no mismatch in fact between retail and wholesale power sales.

4f. Discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed 4 CP methodology (when compared to the methodology used in the MFRs), by shifting target revenue requirements to the rate class away from other rate classes.

A. As noted in the response to 5.c., below, whether any rate class is "negatively impacted" by a particular cost allocation technique or method is relative. The company's response to Request No. 6, below, reflects a comparison of the target revenue allocations using a 12 CP and 1/13th and 50 percent MDS approach at parity to the mitigated 4 CP and 100 percent MDS approach reflected in the 2021 Agreement. However, the response to Request No. 6 does not reflect the intangible benefits associated with a transition to 4 CP, such as encouraging more customer-sited solar, promoting carbon reduction and economic development. It is difficult to quantify the economic value of these benefits with certainty. Additionally, as further explained in the response to Request 5(c), the 2021 Agreement reduces the residential class's increased revenue responsibility by over 20 percent, or $38 million in just the first year of the 2021 Agreement, relative to the level proposed in the initial filing in this case. The 2021 Agreement produces a reduction of the level of increase in the rates of residential customers compared to the proposed rates.

4g. Discuss why the Settlement includes a provision that in the next general base rate proceeding, the filed cost-of-service study will use the 4 CP cost allocation.

A. This provision reflects the general shared belief, noted in response to Request No. 4a above, that movement toward a summer/winter allocation approach, with all production and transmission costs classified as demand-related, is reasonable and appropriate for Tampa Electric in this case. Like most provisions of any settlement, the 2021 Agreement to use the 4CP methodology in Tampa Electric's next base rate case was one of a series of interrelated agreements upon which the settlement was reached and is an integral part of the fabric of the settlement. Along with the specific revenue allocation mitigation implemented in the 2021 Agreement, this provision reflects application of the principle of gradualism in this case and an expectation that the Parties, working together, will continue to "substantially and materially improve the position of all above-parity customer classes toward parity, such that costs are allocated and revenue is collected consistent with 4 CP and full MDS methods."

4h. Clarify whether in the next general base rate proceeding, TECO will only include the 4 CP cost-of-service methodology, or the 4 CP and 12 CP and 1/13 AD methodology.

A. In Tampa Electric's next base rate case filed following Docket No. 20210034-EI, the Company will file its direct case and rate design proposal reflecting a 4 CP methodology. To the extent the Commission's rules require presentation of a 12 CP and 1/13th cost-of-service study in the MFRs, the company will seek a waiver of that requirement; however, a 12 CP and 1/13th cost-of-service study could be made available if the 4 CP or full MDS methodology is opposed in the next general base rate case by an entity other than a Party to the 2021 Agreement or an affiliate of Tampa Electric.

4i. Explain who are the "Precluded Parties" and why would an affiliate of TECO oppose the 4 CP and full MDS.

A. The term "Precluded Parties" is defined in Section 6(d) at p. 25 of the 2021 Agreement and includes Tampa Electric, its affiliates, and the Consumer Parties. The term "Affiliates of Tampa Electric" was added in an abundance of caution.

TAMPA ELECTRIC COMPANY
FIPUG Revised 4CP/MDS Class Cost of Service Study at Present Rates
Test Year Ending December 31, 2025
(Dollar Amounts in Thousands)

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	OPERATING REVENUES								
2	Sales Revenue	1,480,725	920,604	95,215	310,482	44,353	23,795	3,570	82,706
3	Other Revenues	37,746	28,285	2,485	6,037	626	107	95	111
4									
5	TOTAL OPERATING REVENUES	1,518,472	948,888	97,700	316,519	44,979	23,902	3,666	82,817
6									
7									
8	OPERATING EXPENSES								
9	Power Transactions	626	316	29	218	35	26	3	-
10	O&M Expense	391,771	258,739	24,534	82,216	9,712	6,237	589	9,744
11	Deprec & Amortiz Expense	531,436	334,070	29,700	123,451	13,851	9,015	589	20,761
12	Taxes Other than Income	101,592	64,446	5,536	23,201	2,611	1,651	120	4,027
13	Income Taxes	(8,327)	(4,782)	2,833	(14,431)	5	(1,501)	297	9,251
14	Gain/(Loss) on Disposal	-	-	-	-	-	-	-	-
15									
16	TOTAL OPERATING EXPENSES	1,017,099	652,788	62,633	214,656	26,213	15,427	1,598	43,783
17									
18									
19	NET OPERATING INCOME	501,372	296,100	35,067	101,863	18,766	8,475	2,068	39,034
20									
21									
22	RATE BASE								
23	Plant in Service	13,418,078	8,423,825	717,445	3,161,681	355,060	226,533	15,218	518,316
24	Plant Held for Future Use	68,034	41,205	3,169	20,032	2,296	1,186	145	-
25	Working Capital	86,671	49,061	4,257	25,431	3,452	2,428	244	1,797
26	Construction Work in Progress	230,175	145,030	12,137	58,751	7,032	4,923	185	2,116
27	Less: Depreciation Reserve	4,004,807	2,548,996	216,615	903,475	100,286	63,638	4,484	167,314
28									
29	TOTAL RATE BASE	9,798,150	6,110,126	520,393	2,362,420	267,555	171,432	11,310	354,915
30									
31									
32									
33	RATE OF RETURN (%)	5.12	4.85	6.74	4.31	7.01	4.94	18.28	11.00
34									
35	RATE OF RETURN INDEX	1.00	0.95	1.32	0.84	1.37	0.97	3.57	2.15

TAMPA ELECTRIC COMPANY

FIPUG-Recommended Class Revenue Allocation
Based on FIPUG's Revised 4CP/MDS Class Cost-of-Service Study
Test Year Ending December 31, 2025
(Dollar Amounts in Thousands)

Line		Present COS Present Revenues		Base Revenue at Present	Base Revenue at Proposed	Base Revenue Increase		Proposed COS Proposed Revenues	
No.	Rate Class	ROR (%)	Index	Rates	Rates	Amount	Percent	ROR (%)	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RS	4.85%	0.95	$920,604	$1,099,876	$192,274	20.9%	7.22%	0.98
2	GS	6.74%	1.32	$95,215	$99,215	$3,112	3.3%	7.22%	0.98
3	GSD	4.31%	0.84	$310,482	$411,077	$92,263	29.7%	7.22%	0.98
4	GSLD Primary	7.01%	1.37	$44,353	$47,903	$742	1.7%	7.22%	0.98
5	GSLD Sub-Trans.	4.94%	0.97	$23,795	$30,000	$5,244	22.0%	7.22%	0.98
6	LS Energy	18.28%	3.57	$3,570	$3,573	$0	0.0%	18.29%	2.48
7	LS Facilities	11.00%	2.15	$82,706	$82,708	$0	0.0%	11.00%	1.49
8	Total Retail	5.12%	1.00	$1,480,725	$1,774,352	$293,636	19.8%	7.37%	1.00

TAMPA ELECTRIC COMPANY

2025 Marginal Energy Costs by Hour by Month

Amounts in $/kWh	Month											
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12
1	0.03635	0.03422	0.03197	0.03006	0.02867	0.02947	0.03021	0.03095	0.03006	0.03065	0.03072	0.03380
2	0.03552	0.03304	0.03040	0.02857	0.02833	0.02940	0.03008	0.03084	0.02985	0.03053	0.03079	0.03297
3	0.03515	0.03307	0.02953	0.02833	0.02829	0.02928	0.02989	0.03075	0.02968	0.03039	0.03053	0.03256
4	0.03524	0.03267	0.02974	0.02780	0.02822	0.02922	0.02988	0.03069	0.02963	0.03030	0.03030	0.03242
5	0.03575	0.03329	0.02994	0.02823	0.02825	0.02911	0.02975	0.03072	0.02963	0.03036	0.03018	0.03271
6	0.03695	0.03427	0.03035	0.02986	0.02830	0.02926	0.02987	0.03074	0.02976	0.03050	0.03087	0.03380
7	0.03919	0.03566	0.03101	0.03026	0.02848	0.02946	0.03005	0.03090	0.03010	0.03100	0.03157	0.03452
8	0.03694	0.03522	0.03134	0.02864	0.02830	0.02924	0.03002	0.03093	0.03003	0.03076	0.03192	0.03277
9	0.03446	0.03267	0.02932	0.02697	0.02560	0.02831	0.02889	0.03011	0.02925	0.03043	0.02949	0.03363
10	0.03490	0.03299	0.02746	0.02506	0.02565	0.02807	0.02925	0.03005	0.02885	0.02884	0.02951	0.03305
11	0.03592	0.03225	0.02829	0.02586	0.02552	0.03052	0.02994	0.03017	0.02984	0.03174	0.02881	0.03316
12	0.03427	0.03209	0.02748	0.02645	0.02902	0.02954	0.03165	0.03385	0.03149	0.03035	0.03024	0.03347
13	0.03405	0.03205	0.02985	0.02743	0.02899	0.03114	0.03204	0.03367	0.02931	0.03190	0.03138	0.03380
14	0.03340	0.03253	0.02929	0.02792	0.03039	0.02970	0.03232	0.03227	0.02945	0.03077	0.03004	0.03389
15	0.03358	0.03299	0.02978	0.02935	0.02885	0.02973	0.03120	0.03238	0.03040	0.03240	0.03204	0.03382
16	0.03397	0.03370	0.03049	0.03334	0.02894	0.03272	0.03109	0.03134	0.03207	0.03376	0.03050	0.03365
17	0.03520	0.03373	0.03198	0.03160	0.03049	0.03194	0.03312	0.03290	0.03244	0.03250	0.03175	0.03479
18	0.04045	0.03837	0.03237	0.03064	0.03346	0.03007	0.03299	0.03210	0.03387	0.03731	0.03309	0.03726
19	0.03779	0.03455	0.03672	0.03581	0.03496	0.03103	0.03131	0.03255	0.03246	0.02947	0.03311	0.03497
20	0.03576	0.03552	0.03224	0.03337	0.02844	0.02858	0.03486	0.03377	0.03272	0.02814	0.03268	0.03516
21	0.03708	0.03419	0.03160	0.02842	0.02910	0.02746	0.03277	0.03389	0.03160	0.02996	0.03229	0.03487
22	0.03683	0.03533	0.03197	0.03521	0.02968	0.03044	0.03349	0.03305	0.03194	0.03171	0.03168	0.03522
23	0.03657	0.03511	0.03176	0.02969	0.02900	0.02981	0.03318	0.03250	0.03173	0.03254	0.03144	0.03490
24	0.03654	0.03494	0.03139	0.03049	0.02883	0.02965	0.03176	0.03111	0.02913	0.03081	0.03135	0.03486

Super Off-Peak Period.