EARTHJUSTICE

June 6, 2024

VIA ELECTRONIC FILING

Adam J. Teitzman
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Docket Nos. 20240026-EI, Tampa Electric Company Petition for Rate Increase

Dear Mr. Teitzman,

On behalf of Intervenors Florida Rising and League of United Latin American Citizens ("LULAC"), I have enclosed the testimony and exhibits of Karl Rábago. Please file these documents in Docket No. 20240026-EI. Please contact me if there are any questions regarding this filing.

Sincerely,
/s/ Bradley Marshall

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served on this 6th day of June, 2024, via electronic mail on:

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DATED this 6th day of June, 2024

/s/ Bradley Marshall
Attorney

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company	)))	DOCKET NO. 20240026-EI

TESTIMONY OF KARL R. RÁBAGO

ON BEHALF OF

FLORIDA RISING AND LEAGUE OF UNITED LATIN AMERICAN CITIZENS

JUNE 6, 2024

I. <u>INTRODUCTION & WITNESS QUALIFICATIONS</u>

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

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

Q. Please list your formal educational degrees.

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

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

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

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

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

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

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

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

II. OVERVIEW OF TESTIMONY AND RECOMMENDATIONS

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

A. My focus in this testimony is on the spending and associated rates proposed by Tampa Electric Company ("TECO" or the "Company"), a wholly owned subsidiary of Canada-based Emera Corporation ("Emera"). I explain how TECO proposes to regressively increase economic burdens on its residential customers as a condition of electric service. TECO seeks the Commission's support in order to inflate profits for Emera, a foreign holding company, through the extraction of monopoly rents from those customers.

In this testimony I point out how TECO's residential customer electric bills are already among the highest in the nation and would, if the Commission accepts TECO's proposals, go even higher. I show how current and proposed rates excessively burden low users of electricity, who are TECO's lower income customers. And I point out how Emera burdens its Florida customers to an unreasonably higher degree than it does its other regulated utility operating companies.

In this testimony I point out how TECO's residential customer electric bills are already among the highest in the nation and would, if the Commission accepts TECO's proposals, go even higher. I show how current and proposed rates excessively burden low users of electricity, who are TECO's lower income customers. And I point out how Emera burdens its Florida customers to an unreasonably higher degree than it does its other regulated utility operating companies.

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

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

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

A. Today, about 64% of Emera's total earnings are taken from Florida.[1] Emera and TECO seek to increase its revenues from Florida customers by about $1.162 billion over the years 2025 through 2027,[2] with about $555 million of that increase proposed for 2025.[3] The $555 million in proposed rate increases is based, approximately, on the following key drivers:[4]

$145 million, or about 26% of the total, is pure profit associated with increasing the return on equity ("ROE") and the share of the capital structure to be derived from more expensive equity (as compared to debt).

$185 million, or about 33% of the total, is related to capital investment projects.

$160 million, or about 29% of the total, is related to increased depreciation costs and dismantlement costs to make way for new capital investments.

$40 million, or about 8% of the total, is related to increased operations and maintenance ("O&M") costs for capital investments.

$20 million, or about 4% of the total, is for other proposed spending.

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

A. No. TECO's growth in earnings, base revenue growth, and base revenues growth per residential customer are dramatically out of proportion to and unjustified against growth in customer count and energy sales over the years 2018 through 2023.[5] Moreover, the data shows that Emera and TECO profit increases have primarily been on the backs of residential customers.

Table KRR-1: TECO Metrics Growth, 2018-2023

TECO Metrics Growth 2018-2023	Cumulative Growth	Cumulative Growth (%)	Average Growth/Year (%)
Residential Customers (#)	72,058	10.75%	2.15%
Total Customers (#)	77,891	10.30%	2.06%
Energy Sales (MWh)	1,158,489	5.90%	1.18%
Annual Earnings ($)	$ 2,848,655	48.84%	9.77%
Residential Base Revenues ($)	$ 239,606,122	36.12%	7.22%
Total Base Revenues ($)	$ 288,463,684	24.67%	4.93%
Residential Base Revenues per Customer ($)	$ 227	22.91%	4.58%

Q. Can these impacts be seen in TECO residential customers' average bills?

A. Yes. Average TECO residential bills are among the highest in the nation, and the proposed increases would take them even higher. According to the U.S. Energy Information Administration's ("EIA") Sales and Revenue 2023 data and data provided by TECO, the average TECO residential bill under 2023 rates is higher than all other major Florida utilities, higher than the national average by almost 40%, and higher than the average residential electric bills in every other state except Hawaiʻi and Connecticut.[6]

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

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

- Ending TECO's reliance on the Minimum Distribution System ("MDS") method of classifying demand-related costs as customer costs to be recovered through fixed customer charges.
- Reducing TECO's ROE to 9.50%.
- Disallowing use of the 4 Coincident Peak ("CP") method for cost allocation and replacing it with a 12CP methodology.
- Reducing proposed increases in TECO connection and reconnection service charges by 80%.
- Eliminating TECO's proposed Polk fuel oil project.
- Disallowing TECO's South Tampa resilience project absent significant

project funding from the Federal government and/or the U.S. Department of Defense.

- Disallowing further spending on new building construction until TECO produces a comprehensive benefit-cost analysis ("BCA") that fully considers alternatives to new building construction.
- Disallowing all costs related to incentive compensation absent new performance metrics that directly measure improvements in customer affordability, especially among low-income customers, and the removal of incentives for meeting Emera earnings-per-share objectives through methods that worsen affordability.
- Requiring TECO to produce BCAs to support all requests for capital spending projects for $1 million or more.

III. FOUNDATIONAL DATA ON FLORIDA RESIDENTIAL ELECTRIC BILLS

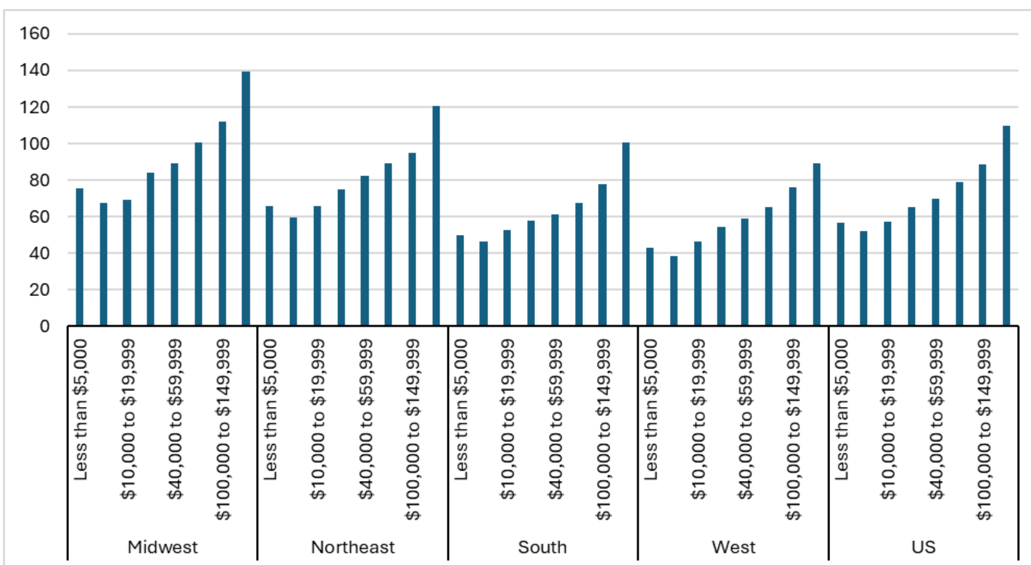
Q. Why are you focused on electric bills for residential customers?

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

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

A. According to the EIA Residential Energy Consumption Survey ("RECS") data the average monthly level of electricity usage by residential customers in Florida is 1,165 kilowatt-hours ("kWh") per month.[7] Lower-income customers across the U.S., on average, use less energy but spend a greater percent of their income on energy costs compared to higher-income customers. According to 2020 EIA RECS data,[8] there is a clear correlation between income and electricity use, with the lowest income customers consuming as little as half as much energy annually compared to their wealthier counterparts. Florida is in the South region and South Atlantic sub-region. The correlation between energy use and income level is also true in Florida.

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



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

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

A. Customers with high energy burdens are vulnerable to rate and bill volatility. Month-to-month changes in rates that might not frustrate the household budgets of well-to-do customers can cause rate shock to customers with high energy burdens. Low-income customers often live on the edge of economic or energy insecurity—an inability to meet basic household energy needs that sometimes referred to as the "heat (or cool) or eat" dilemma.[9] An unaffordable electric bill can create a long-lived cascade of household economic problems, made worse with pancaking fees and charges from utilities and other businesses. Energy insecurity is not just an economic issue, but a social and public health matter as well.[10] For these and other reasons, understanding customer energy burdens informs the spending and rates that a utility electric service provider proposes to impose on customers.

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

A. The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy has created a Low-Income Energy Affordability Data Tool ("LEAD Tool") that documents key affordability metrics across the U.S.[11] The latest data is from 2020 and shows that at that time, nearly one million Florida households had income levels below 100% of the Federal Poverty Level,[12] and nearly 2.4 million Florida households had income levels below 200% of the Federal Poverty Level. According to the Florida Department of Health, the number of Floridians living in poverty grew to 2,725,633 in 2022, based on U.S. Census data.[13]

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

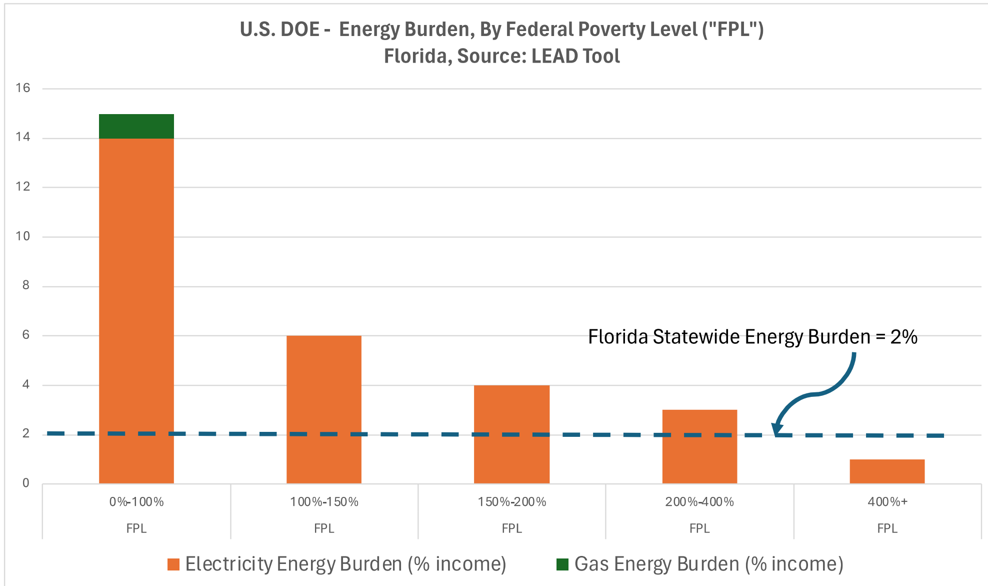
Table KRR-2: Households and Energy Burdens at or below 100% and 200% of Federal Poverty Level

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

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

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

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



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

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

Q. Can highly burdened households simply cut back on energy use or use energy more efficiently to reduce their electric bills or the impact of those bills on household budgets?

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

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

A. Very little. TECO is not able to provide data about the numbers of customers whose household incomes are at or up to 200% of the Federal poverty level.[14]

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

A. Practically nothing. As a former combat arms U.S. Army officer, I look to what leaders say to initially gauge the culture and climate of an organization. I reviewed the testimony of Mr. Archie Collins,[15] who holds the title of president and chief executive officer for TECO for what he said about affordability and found that the words "affordable" or "affordability" do not appear at all. While Mr. Collins asserts that TECO has a strategic objective of creating value for customers,[16] none of his description of that objective directly references affordable rates. Mr. Collins asserts that investments in fossil generation plant improvements and life extensions and new solar will save customers on fuel costs.[17] Those savings are merely incremental in a system that relies on climate-changing fossil fuels for 88% of its generation capacity.[18]

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

A. Emera and TECO propose excessive new costs for customers and an unconscionably regressive assignment of those costs to its customers who can least afford the burden. As show in Table KRR-3,[19] the lowest users of electricity—who are also amongst TECO's least-wealthy customers—are slated to bear shocking base rate and bill increases if the Commission approves TECO's rates and rate designs. As shown in the table, all residential customers using less than the average monthly amount of electricity would see a 10% or greater increase in their bills, while the wealthiest customers who use three times as much electricity as average would only see bills increase by 5%.

Table KRR-3: TECO Proposed Bill Increases by Usage Level, in $ and %[20]

	TECO	
kWh/Month	DOLLARS	PERCENT
100	$ 11.71	34%
250	$ 12.67	24%
500	$ 14.27	17%
750	$ 15.86	14%
1000	$ 17.46	12%
1165	$ 18.25	11%
1250	$ 18.66	10%
1500	$ 19.87	9%
2000	$ 22.28	8%
3000	$ 27.10	6%
5000	$ 36.74	5%

Q. How do Emera and TECO seek to impose these unjust rates?

A. TECO's tools of choice are fixed and unavoidable charges, massive and unjustified capital spending projects, unreasonable increases in cost-plus profits added to spending, and the use of a cost allocation methodology for plant costs that unjustly burdens residential customers. I address these issues further in this testimony.

IV. <u>TECO'S RESIDENTIAL FIXED CUSTOMER CHARGE PROPOSAL IS FLAWED AND UNJUST, AND THE COMMISSION SHOULD DIRECT TECO TO INSTEAD USE THE BASIC CUSTOMER METHOD</u>

Q. What is your recommendation to the Commission regarding TECO'S proposed fixed customer charges and the methods used by TECO to calculate the proposed charges?

A. The Commission should reject the TECO's proposed fixed customer charges and instead approve a fixed customer charge of no more than $0.43 per customer per day for the residential class, based on a re-calculation of customer costs that excludes demand costs incorrectly classified as customer costs under the Minimum Distribution System ("MDS") method proposed by the Company. With that step, the current proposed fixed customer charge would be reduced by more than half. TECO should be further directed to eliminate other cost classifications that are demand-related in order to further reduce the approved fixed customer charge. The Commission should further direct TECO to calculate fixed customer charges only using the basic customer method and to allocate any demand-related changes in revenue requirement to volumetric base rates. Finally, the Commission should direct TECO to use only the basic customer method in all future general rate cases.

Q. What fixed customer charge does TECO propose for residential customers?

A. The Company proposes to increase the current daily per-customer fixed customer charge of $0.71 to $1.07—an increase of $0.36 or 51%.

Q. What does TECO calculate as customer costs in this proceeding?

A. TECO witness Jordan Williams describes the way that TECO classifies demand related costs as customer costs under the MDS.[21] TECO's MDS is based on a fantasty hypothetical distribution system sized to meet the demands of its customers when those customers use no energy and place no demand on the system. The MDS uses mathematical formulae[22] to extrapolate these artificial costs for a distribution system that is sized to meet load[23] but then serves no load because it is installed "in readiness."[24] TECO assigns those artificial costs to customers as customer costs. This assignment is made despite TECO's assertion that customer costs are costs associated with customer "connectivity" to the grid and are not related to capacity requirements[25] and that TECO defines demand costs as costs associated with customer maximum load requirements,[26] and despite the fact that customers don't connect to the grid in order to *not* use energy.

Q. Does TECO's MDS approach account for variation in customer geographic density, or for the fact that low use customers require much less expensive connectivity investments than high users?

A. No. The MDS that TECO uses is designed to extract monopoly rents from customers despite the actual costs associated with establishing their connection to the grid,[27] and even though when customers use the grid, they use it at very different levels—levels that are reflected in the sizing of distribution system components. Simply stated, TECO eschews the most fundamental cost of service rate making principle—cost causation—so as to charge customers for costs they do not cause simply by becoming customers under a rate that customers cannot avoid. Under TECO's approach, low use customers who require much smaller and less expensive distribution system investments are required to subsidize the higher demand-related costs of larger, wealthier users. TECO uses the MDS to perpetrate a massive cost shift.

Q. How does TECO justify its use of such a regressive and unjust method of classifying customer costs?

A. TECO asserts that its MDS approach aligns with the NARUC Electric Utility Cost Allocation Manual. However, the NARUC Cost Allocation Manual is descriptive and not normative; it does not serve as justification for use of the minimum system and minimum or zero intercept methods.[28]

Q. How do differences in fixed customer charges emerge from different methods used to classify cost when they all start from a single common pool of cost-of-service data?

A. The differences arise based on which costs are classified as customer costs and whether the utility performs calculations on underlying data to classify demand-related costs as customer costs. The basic customer method identifies costs that vary only with the number of customers—costs that are incurred to connect a customer to the network. The zero intercept and minimum system methods, like TECO's MDS approach, classify costs as customer costs that are related to meeting customer demand for energy and which are not actually caused by connection of the customer to the grid. Again, these minimum system methods mathematically extrapolate from costs incurred to meet demand, and hypothetically reflect the costs of infrastructure to serve customers who use no energy at all.

Q. Does the method of classifying customer costs impact the total amount of revenue requirement reflected in rates?

A. No. Under the zero-sum process of rate design, lower fixed charges mean more revenue is recovered in volumetric rates; higher fixed charges result in lower volumetric rates. In both, the total revenue to be collected is the same.

Q. Does it matter, then, whether costs are collected through a fixed charge or through a volumetric charge?

A. Yes, very much so. Fixed charges are inherently regressive—they have greater cost impact on low-users who are often also low-wealth customers. Guaranteeing non-bypassable revenues through high fixed customer charges is extremely desirable to TECO and Emera in order to meet the expectations for steady generation of profits promised to investors. Guaranteeing recovery of fixed costs associated with infrastructure spending, as occurs when these costs are recovered through a non-bypassable fixed customer charge, creates an incentive for the utility to increase that kind of spending. Increasing fixed non-bypassable charges has an impact on the cost-effectiveness of energy efficiency, distributed generation, and other distributed energy resource ("DER") investments by customers because higher non-bypassable charges means lower volumetric rates and therefore result in longer payback on customers' investments designed to reduce usage of utilitysupplied energy. In sum, the decision about whether to recover costs through fixed charges or volumetric rates is a decision about what price signals the rate sends—both to customers and to the utility; it is a fundamental question of rate design.

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

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

Q. Are there other disparate impacts from high fixed charges on lower-income customers?

A. Yes. In my experience, low users of electricity have lower and flatter load curves—less peaky demand—than high users. As a result, when peak-driven demand-related costs are allocated to the residential class and some of those costs are included in fixed customer charges, low-use, often low-wealth customers are required to pay more than their fair share of these costs. As a result of TECO's reliance on the MDS approach to classify customer costs, low-wealth customers are being charged for costs driven by the usage levels and patterns of more well-to-do, higher-demand customers. When fixed customer charges do not differentiate between the usage levels and patterns of customers as TECO's charges fail to do,[29] they unjustly discriminate.

Q. How do high fixed customer charges discourage adoption and weaken the economics of energy efficiency, conservation, and distributed renewable energy?

A. High fixed charges work against energy policy and rate making goals favoring and encouraging energy efficiency and increased use of renewable energy resources in two insidious and overlapping ways. First, they increase the amount of the customer's total bill that cannot be reduced through efficiency, conservation, renewable energy subscription, or self-generation. This makes customer actions that would increase efficiency, conservation, and customer participation in renewable generation less likely to occur. Second, in the zero-sum-game of rate design, the charges also result in lower volumetric rates. This has the effect of reducing the marginal value of energy efficiency, conservation, and customer-sited renewable generation, also making those actions less likely to occur. For example, when use-based charges are deflated by 20% by shifting the revenue requirement to the fixed charges, every efficiency measure, conservation practice, and solar investment takes 20% longer to deliver a payback on its initial investment. As a result of these two effects, basic economics dictates that customers are less interested in reducing usage because it will yield less benefit in reducing bills. I have seen no evidence that TECO has conducted or used a demand elasticity study—an analysis to determine how usage behaviors change in response to price changes—to inform its rate design proposals.

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

A. No. As far as I can tell, TECO does not directly assert that it should charge high fixed customer charges just because it has high fixed costs. Rather, TECO takes an indirect path: TECO's position is that it should be charging higher fixed customer charges because it uses a method that classifies higher amounts of fixed costs as customer costs—an intentional choice of classification method that inexorably leads to the same result—higher fixed charges.

Before I address the significant flaws in the MDS method used by TECO and in other minimum system or zero-intercept methods, it is important to address the oft-heard argument that rate design should mimic cost structure. In that regard, I simply note that after thirty years in utility regulation I have yet to find a single authoritative economic text to support the argument that economic efficiency results from mimicking cost structure in rate design.

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

A. There are very few. The vast majority of high fixed-cost businesses do not impose fixed charges at all and would likely not survive long in a competitive market if they did. For example, airlines and transit services do not require monthly subscriptions, neither do hotels or shopping malls. There are some businesses like warehouse retailers and on-line shopping services with optional levels of fixed charges, but those charges appear designed to increase sales to loyal customers—which, in the electric utility regulatory setting would be called "load building." The fact that many businesses must make large fixed-cost investments does not translate into fixed charges in almost all business cases; rather, the forces of competition reward business for careful investment analysis, inventory management, and cost control—all disciplines that if mastered would greatly improve the performance of electric and gas utilities far more than a guarantee of fixed costs recovery through non-bypassable customer charges.

Q. Do any other Emera operating utilities employ the MDS or other minimum system or zero-intercept approaches?

A. No.[30]

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

A. Yes, prices advance efficiency when they reflect marginal costs, but that is an entirely different issue than reflexively asserting that fixed charges should be used to collect marginal fixed costs as a matter of rate design. Marginal costs can be recovered through either fixed or variable charges. By weakening the price signal that customers see from marginal changes in consumption, high fixed charges deviate from marginal cost pricing.

Q. How has TECO analyzed price signal impacts from its high fixed charges for electric service?

A. TECO provided "typical bill" calculations of the bill impacts of its rate proposals via MFR filings, but it has not otherwise studied the impacts of its proposed rates on residential customers, or upon low-wealth customers in particular.

Q. Are high fixed charges and methods that assign higher levels of customers costs appropriate as a mechanism to ensure that low-use customers pay their fair share of demand-related fixed costs?

A. No. Some utilities attempt to justify higher fixed customer charges on the basis that when large amounts of costs are classified as customer costs, higher fixed charges are necessary to avoid subsidization of low-use customers by high-use customers. This argument is a logical fallacy known as "begging the question." That is, it assumes that the minimum system and zero-intercept methods that classify more costs as customer costs are themselves sound rate making methods in order to justify assigning more costs for recovery through fixed customer charges. These arguments are seldom accompanied by anything but an assumption that because low users pay less in fixed costs than the *average* customer in the class, they are not paying enough.

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

A. Where a customer charge is used, a good rule of thumb is this: If the cost disappears because the customer leaves the system, the cost is a customer cost. The consumption function of the meter, the service drop, and a reasonable share of customer service spending would all meet this test, and therefore these costs are included in approaches like the basic customer method. Likewise, if the cost remains after a customer leaves the system, the cost is not a customer cost. Transformers, secondary and primary distribution lines, program-specific marketing and customer care expenses, uncollectible costs, and general operations, administrative and maintenance expenses and taxes are all non-customer costs, and the principle of cost-causation dictates that those costs should not be recovered through a fixed or customer charge.

Q. Please provide more detail on how costs are classified to the customer costs category?

A. Some costs can be easily and objectively classified as customer costs. In general, the customer costs are the costs incurred to connect a new customer to basic electric service. These include the cost of establishing service, which includes a fraction of a customer accounts system, billing software, and the time that customer service representatives spend on establishing new accounts. These costs are all costs that pass the simple test—they go away if the customer goes away. These costs also include the costs related to the consumption function of meter purchase, installation, activation, and service, but not the entire costs of modern meter functions. And these costs include the incremental costs of the service drop from the last, smallest transformer to the customer meter box. These costs are classified as customer costs under the dominant method for classifying customer costs—the basic customer method. In my opinion, this is the most appropriate method.

In other words, the customer costs category and, therefore, the customer charge, should reflect no more than the costs incurred by the utility to connect the average customer to the electric system for service. I would note that the strongest price signals would be sent under the "new customer" method, which only charges customers with the incremental connection costs for new customers on a per-customer basis, and which I believe the Commission should order TECO to study in preparing its next general rate application.

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

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

> [The customer costs] are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer.[31]

Simply stated, Bonbright's definition—which describes the basic customer method—ensures that the customer charge should be limited to the marginal cost of connecting the customer to the grid and should include only costs that vary directly with the number of customers.[32]

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

A. Adhering to the principle that customer costs are costs that vary with customer count and almost or entirely without regard for usage advances other ratemaking principles such as equity and cost-causation and preserves the power of volumetric charges as a price signal. Residential customers can see a direct correlation, both positive and negative, between their level of usage and their contributions to cost creation when energy- and demand-related costs are recovered through volumetric charges. Allocating demand-related costs or even unallocable costs (as Bonbright viewed the minimum system costs) to the fixed customer charge eliminates, or at least severely weakens, the price signal impact.

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

A. Costs directly related to grid connection for new customers include a portion of the cost of a meter, billing and metering services, and collection costs—in Bonbright's words, the costs the utility "must incur in taking on another customer."[33] By my calculation, the figure is less than 43 cents per customer per day for TECO residential customers.

Q. Are all the costs classified by TECO as customer costs the costs that TECO incurs to connect a customer to the grid?

A. No. TECO explicitly includes costs that are associated with meeting customer demand for energy services and that are not directly related to customer connection.[34]

Q. Have the problems associated with the minimum system approach been previously studied or analyzed?

A. Yes. The problems inherent in the minimum system approach have been well understood for decades. Indeed, James Bonbright addressed the issues head-on in 1961:

> [T]he really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system—a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized

distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution

> system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully-distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that 'the sum of the parts equals the whole.' He is therefore under impelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.[35]

Thus, as the late professor correctly noted, the minimum system analysis does not identify customer costs but partially non-demand and partially non-energy costs. Using it to set a customer charge is nothing more than a preference to socialize the costs rather than have customers pay for them based on usage.

Q. Have more modern articulations of generally accepted rate making principles than Bonbright addressed the minimum system and minimum and zero intercept methods?

A. Yes, in 2020, the Regulatory Assistance Project published a new manual for electric cost allocation that addresses minimum system and minimum and zero intercept methods.[36] I reprise the discussion from the RAP Cost Allocation Manual in great detail because of the thoroughness of its explanation:

> [M]ore general attempts by utilities to include a far greater portion of shared distribution system costs as customer-related are frequently unfair and wholly unjustified. These methods include straight fixed/variable approaches where all distribution costs are treated as customer-related . . . and the more nuanced minimum system and zero-intercept approaches included in the 1992 NARUC cost allocation manual.

The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related. This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.

1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number . . .

2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers. Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage

duration).

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.

4. The "minimum system" would still meet a large portion of the average residential customer's demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system.

5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted. However, the transformer industry could produce truly minimum-sized utility

transformers, the size of those used for cellular telephone chargers, if there were a demand for these.

6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.

7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.

8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with contributions in aid of construction, …. Factoring in the entire length of the system,

including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines.

Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid overhead distribution equipment only under several unusual circumstances. These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility, particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

The related zero-intercept method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load. The zero-intercept method usually involves statistical regression analysis to decompose the costs of distribution equipment into customer-related costs and costs that vary with load or size of the equipment, although some utilities use labor installation costs with no equipment. The idea is that this procedure identifies the amount of equipment required to connect existing customers that is not load-related (a zero-kVA transformer, a zero-ampere conductor or a pole that is zero feet high). The zero-intercept regression analysis is so abstract that it can produce a wide range of results, which vary depending on arcane statistical methods and the choice of types of equipment to include or exclude from an equation. As a result, the zero-intercept method is even less realistic than the minimum system method.[37]

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

A. The Company should use the basic customer method. The RAP Cost Allocation Manual provides additional explanatory detail that the Company should consult.[38]

Q. Are the minimum system and zero-intercept methods common practice in the majority of states?

A. No. The minimum system method is out of step with practice in the majority of states.[39] The RAP Cost Allocation Manual cites several regulatory decisions that have rejected the methods.[40]

Q. If, as Bonbright suggests, some of the legitimate and reasonable costs that TECO's MDS allocates to the customer cost category are not customer costs or demand-related costs, then how do you propose that TECO recover those

costs?

A. First, it is important to recognize that there is no general principle of rate making that requires a cost to be recovered through a particular kind of charge solely because of the category to which the cost is assigned.[41] Rate design is a separate rate making step following cost of service analysis, functionalization, and classification. Given the important policy, equity, and market issues that I discuss in this testimony, prudent distribution system costs properly allocated to residential customers that may not neatly fit in the customer or demand category should be recovered through the volumetric delivery charge. The typically high correlation between energy use and demand means that assignment of transmission and distribution costs (other than the costs to connect) to volumetric rates creates a more efficient price signal than assigning those costs to fixed customer charges.

Q. Does the minimum system method support just, reasonable, and equitable rates?

A. No. The major problem with the minimum system methods is that they are designed to meet a predetermined revenue recovery level choice rather than to reflect, as best is possible, objective reality about system costs and cost-causation. Indeed, the underlying policy choice made in adopting minimum system methods is that costs should not be paid according to causation and, instead, socialized. The minimum system methods assign all customers a per-customer share of the system costs regardless of the very real differences in the cost to connect and serve different kinds of customers, even customers in the same class.

Q. Do TECO's fixed charges proposals raise any other economic efficiency concerns?

A. Yes. I have explained how the increased fixed charges and companion lower base volumetric rates are economically regressive and send price signals that disincentivize investment in energy efficiency and distributed generation. They also send the wrong price signal to TECO and Emera. When marginal distribution infrastructure costs are allocated to volumetric rates, demand elasticity means that sales will go down as customers seek alternatives to high usage and higher bills. In this way, a Commission decision to limit the costs that can be loaded into fixed charges serves as the classic substitute for the forces of free market competition. Conversely, the utility that is allowed to increase spending and allocate those costs to non-bypassable charges will have less incentive to operate and spend in a least-cost manner because it will be immunized, to a degree, from consumption changes that accompany higher prices. That is, a higher fixed customer charge can encourage economic inefficiency and waste, *and* stronger revenues by the Company. Revenues that a regulated monopoly can extract from customers without fear or with reduced fear of consumption changes are called monopoly rents—neither markets nor regulatory commissions should encourage them by allowing high-fixed charge rate designs.

Q. Please summarize your testimony on this issue. If some of the minimum system costs are, according to Bonbright, neither pure customer costs nor pure demand costs, how should they be treated?

A. It is important to start with the reminder that the only fixed and variable costs included in the customer charge should be those true customer costs that would go away in the absence of the customer. Then, the decision on how to treat minimum system costs that are not customer or demand costs should be informed by policy. On the one hand, recovering these costs on a per-customer basis enriches shareholders with more certain revenue recovery; increases the incentive for profit-generating infrastructure investments even if not cost-effective; decreases the incentive for energy efficiency, conservation, and distributed generation investment; and weakens price signals relating to fixed costs creation in general. The alternative is recovering these costs on a volumetric basis, as is done in the majority of states. This alternative provides incentives to customers to become more efficient and to invest in clean distributed generation, sends stronger price signals to the utility to manage and reduce infrastructure costs, aligns bill impacts with customer cost-causation, and aligns with generally-accepted rate design and energy policy goals.

Q. What do you conclude about the fixed charges proposed for approval in this case?

A. The charges are too high because they unjustly and unreasonably charge customers for costs that are not customer costs, and they are bad rate making policy. TECO has calculated an unreasonable residential customer charge of $1.07 per customer per day based on its MDS method that should not be approved by the Commission.

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

A. The Commission should approve a fixed customer charge for residential customers based on treatment of MDS costs as demand costs. I calculate, using TECO data, that a reasonable customer charge should be to be no higher than $0.43 per customer per day.

Q. Why do you say that the residential fixed customer charge should be *no higher* than 43 cents per customer per day?

A. Consistent with my testimony, the Commission should also direct TECO to exclude from the calculation of the residential customer charge additional amounts that are not true customer costs. TECO records all customer relations and customer service expenses as customer costs.[42] However, according to TECO, only about 12% of the customer service call volume is related to turning on service and connecting customers to the grid.[43] The remainder of customer service expenses relates to account issues, service disconnections, payment issues, and other activities that are associated with ongoing customer use of electric services.[44] Likewise, uncollectible expenses are directly a result of use of energy and demand and are not basic customer costs.

TECO also deploys various sizes and types of equipment and infrastructure to connect customers to the grid. The costs that should be classified as customer costs should only be those associated with the smallest, least expensive equipment necessary to connect customers to ensure that low users of electricity are not required to subsidize the equipment and infrastructure needs of larger consumers with higher demand for electricity. The Commission should direct TECO to further reduce the residential fixed customer charge by eliminating connection costs attributable only to larger users.

Making these changes will reduce the level of a just and reasonable residential fixed customer charge below the 43 cents per customer per day that I initially calculate.

Q. How do you propose that TECO recover demand-related costs that should not be recovered through fixed customer charges?

A. I propose that the adjustments to remove the effects of TECO's use of the MDS approach be addressed in a revenue neutral manner. That is, any just and reasonable costs that are not collected through the customer charge should be assigned as demand related and recovered through the residential volumetric charge.

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

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

I will provide a table of estimated bill impacts later in this testimony that includes the elimination of the MDS approach as well as my recommendation for TECO's allowed ROE.

V. **<u>TECO'S ROE AND CAPITAL STRUCTURE PROPOSALS ARE EXCESSIVE AND UNJUSTIFIED, AND SHOULD BE REDUCED</u>**

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

A. TECO proposes a midpoint allowed ROE of 11.50%, with potential for earning up to 12.50% in this rate proceeding.[45] TECO also proposes a 54% equity ratio from investor sources.[46]

Q. How does TECO justify its ROE and capital structure requests?

A. After reviewing the testimony of TECO witnesses Chronister and D'Ascendis, upon whom TECO's profit requests primarily rely, I find that TECO's argument boils down to the fact that it wants to spend a lot of money and that it wants to make a lot of money when it does so. TECO presents no evidence of financial impairment or difficulties in obtaining capital at reasonable rates. As discussed in this testimony, a significant amount of TECO's proposed spending is excessive and unjustified. Although TECO's primary ROE witness, Dylan W. D'Ascendis, modifies and applies several analysis models to argue that the proposed ROE and capital structure are reasonable,[47] his arguments can be boiled down to four: (1) interest rates and inflation were higher when this rate application was prepared than they were in previous years; (2) TECO proposes to spend a lot of money; (3) TECO should earn profits at levels that are indexed against those of unregulated businesses; and (4) TECO's profits should be inflated because it faces high risk based on the potential costs associated with extreme weather events.[48]

Q. Do you agree with these justifications?

A. No, and for several reasons. As I have testified, TECO's primary business drivers of customer and sales growth have been extremely modest in effect and do not justify the dramatic increases in spending and earnings that TECO has experienced and proposed. TECO is overearning against these drivers and its spending and profits should be reduced, not further inflated. Second, TECO's proposed new spending is unreasonable and unjustified in many cases. If these proposals were moderated to reasonable levels, TECO could maintain strong financials without making outsized profits. TECO wants to spend about $1.6 billion each year in 2025, 2026, and 2027 on capital projects, growing its rate base and profits.[49] Third, TECO's ROE proposal is out of step with awarded ROEs in recent years. According to the Edison Electric Institute ("EEI"), awarded ROEs since the start of 2022 have averaged 9.52%, as have awarded ROEs dating back for five years.[50] In fact, awarded ROEs over the past ten years have been only slightly higher, at 9.67%.[51] Fourth, TECO's proposed ROE and capital structure are out of step with the allowed rates of return for all other Emera operating companies.[52] Fifth, the Federal Reserve Bank is continuing efforts to control inflation and resume interest rate reductions.[53] Sixth, while TECO faces climate change risks associated with severe weather events, such risks are now unfortunately common across the U.S. and around the world. TECO has finally started taking some steps towards reducing its dependence on fossil fuels, and if it is serious about climate risk, should continue those efforts.[54] In addition, if TECO wants to protect investors, it should not do so with outsized profits for a risky system, but through concerted planning and efforts to change the basic structure of its system, including through more aggressive support for deployment of distributed energy resources such as distributed storage, distributed generation, energy efficiency, strengthen building codes and standards, and other similar measures. TECO's risk profile and actions to date do not justify returns that are out of step with regulated electric utility averages.

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

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

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

A. Unless and until TECO shows that it is not seeking to grow Emera profits on the backs of Florida residents, and it offers a comprehensive plan for mitigating and not exacerbating its contributions and exposure to climate-related severe weather, TECO's allowed ROE should not exceed the average awarded to other utilities, including other Emera utilities. For these reasons, I recommend that the

Commission award TECO a midpoint ROE of no higher than 9.50%.

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

A. Based on the information provided by TECO in this case, I estimate that an allowed ROE of 9.50% would reduce the overall revenue requirements by about 7%. According to TECO, a 200 basis point reduction in the allowed ROE from 11.50% to 9.50% will reduce TECO's total revenue requirement by more than $123 million and provide a significant improvement in electric service affordability.

Q. What is the combined impact of your proposal to eliminate the MDS approach and to reduce the allowed ROE to 9.50%?

A. While TECO would have to provide the exact amounts, I estimated that the rates and bills resulting from eliminating the MDS approach and an ROE midpoint of 9.50%. The results significantly improve both the level and distributional fairness of TECO's rates and are shown in Tables KRR-4 and KRR-5, and reflect elimination of the MDS approach on a revenue-neutral basis.

Table KRR-4: Current and Proposed Residential Rates with MDS Removed and 7% Reduction Applied to Volumetric Rates to Estimate Impact of 9.50% ROE

CURRENT AND PROPOSED RESIDENTIAL (RS) RATES				
RATE	TECO CURRENT	TECO PROPOSED	DIFFERENCE PROPOSED ($)	DIFFERENCE PROPOSED (%)
Fixed Customer Charge (per Customer/Day)	$ 0.71	$ 1.07	$ 0.36	51%
Fixed Customer Charge (per Customer/Month)	$ 21.60	$ 32.55	$ 10.95	51%
Energy & Demand Rate 0-1000 kWh (Cents/kWh)	6.65	7.49	$ 0.84	13%
Energy & Demand Rate >1000 kWh (Cents/kWh)	7.80	8.49	$ 0.69	9%

RATE	TECO PROPOSED	RÁBAGO PROPOSED	DIFFERENCE PROPOSED ($)	DIFFERENCE PROPOSED (%)
Fixed Customer Charge (per Customer/Day)	$ 1.07	$ 0.43	$ (0.64)	-90%
Fixed Customer Charge (per Customer/Month)	$ 32.55	$ 13.08	$ (19.47)	-90%
Energy & Demand Rate 0-1000 kWh (Cents/kWh)	7.49	8.59	1.10	17%
Energy & Demand Rate >1000 kWh (Cents/kWh)	8.49	9.52	1.03	13%

Table KRR-5: Teco and Rábago Proposed Changes to Current Bills and to Effective Total Cents Per Kwh as Various Usage Levels

	PROPOSED CHANGES TO CURRENT BILLS				PROPOSED CHANGES IN TOTAL CENTS/KWH		
	TECO		RÁBAGO				
kWh/Month	DOLLARS	PERCENT	DOLLARS	PERCENT	PRESENT	TECO PROPOSED	RÁBAGO PROPOSED
100	$ 11.71	34%	$ (7.69)	-23%	$ 34.01	$ 45.72	$ 26.32
250	$ 12.67	24%	$ (4.91)	-9%	$ 20.90	$ 25.97	$ 18.94
500	$ 14.27	17%	$ (0.27)	0%	$ 16.53	$ 19.39	$ 16.48
750	$ 15.86	14%	$ 4.36	4%	$ 15.08	$ 17.19	$ 15.66
1000	$ 17.46	12%	$ 8.99	6%	$ 14.35	$ 16.09	$ 15.25
1165	$ 18.25	11%	$ 11.68	7%	$ 14.35	$ 15.92	$ 15.35
1250	$ 18.66	10%	$ 13.06	7%	$ 14.35	$ 15.85	$ 15.40
1500	$ 19.87	9%	$ 17.12	8%	$ 14.36	$ 15.68	$ 15.50
2000	$ 22.28	8%	$ 25.25	9%	$ 14.36	$ 15.47	$ 15.62
3000	$ 27.10	6%	$ 41.51	10%	$ 14.36	$ 15.27	$ 15.75
5000	$ 36.74	5%	$ 74.02	10%	$ 14.37	$ 15.10	$ 15.85

VI. TECO'S USE OF A 4 CP METHOD TO ALLOCATE RETAIL COSTS UNFAIRLY AND UNREASONABLY BURDENS RESIDENTIAL CUSTOMERS

Q. What impact does TECO implementation of a 4 CP allocation method for production and demand-related retail costs have on residential customer rates and affordability?

A. TECO's use of the 4 CP allocation method unjustly increases the share of production and demand-related retail costs that residential customers must bear relative to other rate classes when compared to the 12 CP or 12 CP 1/13th AD methods. TECO uses the 4 CP method because it agreed to do so in the settlement of its 2021 rate increase application.[55] Along with the use of the MDS method for classifying demand-related costs as customer costs, the use of the 4 CP allocation method adds about $71 million in costs to residential customers that they would not be required to pay under a 12 CP 1/13 AD method without the use of the MDS customer cost method.[56]

Q. How does the cost allocation method change class revenue burdens?

A. The increased burden related to the cost allocation method is a product of two key factors—the relative contribution to total demand that a class places on the retail system, and the number and times when those contributions are measured. All things being equal, customers with higher relative demand—"peakier" demand—will be assigned a higher share of costs than customers with flatter demand patterns when fewer dates that align with overall system peak ("coincident peak") are sampled. Thus, with residential customers generating a larger share of peak demand in general, when load studies focus on a small number of months with the highest demand—as under a more narrowly focused 1 CP or 4 CP approach—more costs are allocated to residential customers. Likewise, if the highest peak days in each of the twelve months in the year are sampled, larger customers will be assigned more costs based on their consistently high usage across the span of a year. Average demand adjustments can also be used to reflect non-coincident peak demand created by a class as a whole. This is the "zero sum game" of cost allocation, and under TECO's management, residential customers lose.

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

A. Although arguments and justifications about which cost allocation method to use are often couched in broad assertions about which method better reflects cost causation, the decision of how to slice the pie of total revenue requirements often devolves to a contest of regulatory political power played out in confidential settlement negotiations. Very large customers with the ability to fully participate in rate proceedings represented by expensive consultants often do better than residential consumer advocates with limited budgets. It is also true that because the number of residential customers and small business customers vastly exceeds the numbers of customers in other classes, assignment of revenue requirement increases to small customers can result in smaller per-unit or per-bill increases relative to other customer classes. Additionally, under a somewhat perverse and certainly unjust theory of inverse elasticity, monopoly utilities often find convincing the argument that excess costs should be assigned to customers with the least opportunity to do anything but pay the charges.[57]

Q. How does TECO rationalize its participation in the 2021 settlement that required it to apply a 4 CP methodology and full implement an MDS approach for assigning demand-related distribution costs to residential customers?

A. Consistent with its almost complete lack of focus on customer affordability, TECO seems quite comfortable with regressive cost allocation and rate design methods imposing increasing shares of the burden of its profit seeking on residential and, to a lesser degree, small business customers. Oddly, TECO asserts that the 4 CP method is more appropriate today because TECO is increasing the solar fraction in its generation fleet,[58] as compared to what have been historically called "baseload" generation like coal plants and "shoulder" combined cycle gas plants. This argument does not serve as a reasonable justification for the use of the 4 CP method. First, it is an argument about the performance nature of generators, not the cost causation characteristics of customers. Second, TECO is using a 4 CP method that weighs 25% of allocated costs based on a January coincident peak—which has little or no relationship to solar production costs. Third, it ignores the fact that low-use, low-income customers often have particularly flat load shapes, especially in the South. Fourth, as TECO admits, the firm capacity of the solar it is adding continues to diminish due to the non-solar peak shift caused by the addition of more solar, as will the amount of energy the solar plants add to the non-solar peak. The residual non-solar peak is what TECO will have to plan on for non-solar generation and what is used to calculate the reserve margin for planning purposes. Solar additions further in the future are estimated to provide smaller contributions to peak firm capacity.[59] Fifth, even in 2021, when this shift would have been smaller, TECO proposed to allocate 50% of solar production to energy based on this shift, a shift that has only accelerated since that time.

Q. What do you recommend?

A. In my opinion, the best measure for which cost allocation method to use is which best serves and promotes the public interest. Under TECO's rates and spending proposals, with the energy burden information that I have presented in this testimony, and in light of general economic conditions, the better approach for TECO would be use of a 12 CP allocation, perhaps with an average demand modifier to address residential contributions to coincident peak demand. Given that solar production costs are driving so much of capital expenditures, and that solar, at best, contributes 50% to some peaks, I recommend using a 12 CP & 50% AD methodology without MDS, as reflected in Exhibit KRR-3 and Exhibit KRR-4 (reflecting my recommended 9.5% ROE with no other additional changes, although other costs should be disallowed as as discussed below), and I recommend the Commission direct TECO to adjust rates accordingly, such as I have done in Exhibit KRR-5. Each of these exhibits was developed by making minimal changes to inputs, consistent with my testimony, to TECO's intact MFR models. At a minimum, if 12 CP & 50% AD is not accepted by the Commission, I recommend that the Commission direct TECO to use their 12 CP & 1/13 AD cost of service study, without the use of the MDS method, and to adjust rates accordingly.

VII. <u>TECO PROPOSES ADDITIONAL UNJUSTIFIED AND UNREASONABLE SPENDING THAT THE COMMISSION SHOULD DENY IN THIS PROCEEDING</u>

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

A. The Commission should act to reign in TECO's proposed spending spree in order to help ensure customers can afford essential electric service. I point out several issues where Commission action is appropriate, though my silence on any particular issue should not be considered support for any TECO proposal. The issues that I propose to call the Commission's attention to include the following:

- The Commission should deny any rate recovery of employee incentive compensation program costs until TECO submits a revised employee incentive compensation plan. TECO's current proposal is to charge customers some $33 million for short- and long-term incentive compensation payments that encourage rate and cost increases to grow net income and that fail to directly address customer affordability at all.[60] The Commission should require TECO to submit a plan that includes shareholder direct “below the line” funding of at least 50% of the incentive compensation program budget and that reflects two major changes: (1) A required performance metric that addresses maintaining and improving customer affordability, especially among residential customer with income levels at or below 400% of the Federal poverty level. In particular, this metric should be addressed with permanent or long-lived actions that do not merely require other customers to pay low-income customer bills. (2) The revision of any earnings-based performance metrics to ensure that only earnings improvements that reflect measurable customer benefits qualify for inclusion in any incentive compensation program.

- The Commission should deny TECO’s proposals to increase service charges for service connection and reconnection above the Florida-wide rate of inflation in the previous calendar year. Electric service is too important and too necessary for survival for TECO to charge $168 per customer for a new service connection, and its proposed fees are out of step with those for other utilities in Florida or operated by Emera.[61] I recommend that these charges be reduced by 80%.
- The Commission should disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. TECO’s current approach to developing major capital projects relies solely on management discretion

and a cumulative present value of revenue requirements ("CPVRR") approach that lacks transparency and objectivity, and that ignores cost-effective alternatives that may offer better, more affordable outcomes.[62] Given the heavy incentive compensation weighting TECO proposes for increasing net income,[63] there is strong management incentive to advance projects that lower CPVRR by the least amount possible. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether TECO spending proposals will result in rates that are fair, just, and reasonable.

- The Commission should disallow any spending on the Polk fuel oil project which would increase dependence on a dirty form of fossil fuel and has not been demonstrated to be cost-effective through completion of a BCA.
- The Commission should disapprove any rate recovery for the so-called South Tampa Resilience Project to be sited at McDill Air Force Base. The $160 million project[64] has several major flaws that must be addressed before the Commission allows it to possibly move forward. First, the project lacks the support of a BCA to ensure that it is the most cost-effective option for obtaining the resilience benefits it is designed to obtain. Second, the project would add new highly-pollution fossil fuel generation to the TECO system mix in the form of reciprocating gas engines. Third, the proposal will receive no direct funding support from the U.S. Department of Defense or the Federal government, and only a 33-year cost-free lease for the land.[65] I find it incredible and unconscionable that TECO would propose a deal in which its hard-working, tax paying customers must subsidize the U.S. government with payments for such a

project.

- The Commission should disapprove any rate recovery for new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction.
- The Commission should disapprove most, if not all, of the rate recovery for the so-called transmission and distribution reliability improvements supported by witnesses Whitworth and Lukcic as unnecessary gold-plating of the system that is destined for quick obsolescence (including a private LTE network for the utility).

VIII. RECOMMENDATIONS

Q. Please reprise your recommendations to the Commission in this proceeding.

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

- Ending TECO's reliance on the Minimum Distribution System ("MDS") method of classifying demand-related costs as customer costs to be recovered through fixed customer charges.
- Reducing TECO's ROE to 9.50%.
- Disallowing use of the 4 Coincident Peak ("CP") method for cost allocation and replacing it with a 12CP & 50% AD methodology.
- Reducing proposed increases in TECO connection and reconnection service charges by 80%.
- Eliminating TECO's proposed Polk fuel oil project.
- Disallowing TECO's South Tampa resilience project absent significant

project funding from the Federal government and/or the U.S. Department of Defense.

- Disallowing further spending on new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction.
- Disallowing all costs related to incentive compensation absent new performance metrics that directly measure improvements in customer affordability, especially among low-income customers, and the removal of incentives for meeting Emera earnings-per-share objectives through methods that worsen affordability.
- Requiring TECO to BCAs to support all requests for capital spending projects for $1 million or more, and disapproval of any transmission and distribution system projects until TECO applies a standardized BCA approach to each project.

Q. Does this conclude your direct testimony?

A. Yes.

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[1] TECO Resp. to FL Rising/LULAC INT 103.

[2] TECO Resp. to FL Rising/LULAC RFA 1.

[3] TECO Resp. to FL Rising/LULAC INT 104.

[4] *Id.*

[5] TECO Resp. to FL Rising/LULAC INT 101.

[6] U.S. Energy Info. Admin., EIA-861 M Sales and Revenue Data 2023, available at: https://www.eia.gov/electricity/data/eia861m/archive/xls/sales_ult_cust_2023.xlsx.

[7] U.S. Energy Info. Admin., RECS State Data on Fuel Consumption 2020, https://www.eia.gov/consumption/residential/data/2020/state/pdf/ce2.1.st.pdf (last visited June 4, 2024). Calculated as 47.7 MMBtu * 293.07107 MMBtu/kWh = 1,165 kWh.

[8] *See* U.S. Energy Info. Admin., RECS Data 2020, Tables CE1.1-1.5, https://www.eia.gov/consumption/residential/data/2020/index.php?view=consumption (last visited June 4, 2024).

[9] Diana Hernández, *Understanding 'Energy Insecurity' and Why It Matters to Health,* 167 Soc. Sci. Med. 1, 2 (Oct. 2016) https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5114037/.

[10] *Id.*

[11] U.S. Dept. of Energy, *Low-Income Energy Affordability Data Tool,* Office of Energy Efficiency and Renewable Energy, https://www.energy.gov/scep/slsc/lead-tool (last visited June 4, 2024).

[12] Federal Poverty Level data, which applies to Florida, is available from the U.S. Department of Health and Human Services. For 2020 levels, see https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines/prior-hhs-poverty-guidelines-federal-register-references/2020-poverty-guidelines. For 2024 levels, see https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines.

[13] Fla. Dept. of Heath, *Individuals below Poverty Level (Census ACS),* Florida Health Charts, https://www.flhealthcharts.gov/ChartsDashboards/rdPage.aspx?rdReport=NonVitalInd.Dataviewer&cid=294 (last visited June 4, 2024).

[14] TECO Resp. to FL Rising/LULAC INT 110–112.

[15] TECO witness Archie Collins direct testimony ("Collins Direct").

[16] *Id.* at 5.

[17] *Id.* at 23.

[18] *Id.* at 19–20.

[19] Source: TECO Resp. to OPC POD 1-1, folder "MFR E", file "(BS 197)2025 Proposed Rates MFR.xlsx"

[20] *Id.*

[21] TECO witness Jordan Williams direct testimony ("Williams Direct") at 14, et seq.

[22] TECO Resp. to FL Rising/LULAC INT 60.

[23] TECO Resp. to FL Rising/LULAC INT 59.

[24] TECO Resp. to FL Rising/LULAC INT 62.

[25] *Id.*

[26] TECO Resp. to FL Rising/LULAC INT 55.

[27] TECO Resp. to FL Rising/LULAC INT 62, 64, 65.

[28] Nat'l Ass'n of Regul. Utility Comm'rs ("NARUC"), Electric Utility Cost Allocation Manual at ii (Jan. 1992) ("The [Manual's] writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.").

[29] TECO Resp. to FL Rising/LULAC INT 64, 65.

[30] TECO Resp. to FL Rising/LULAC INT 63.

[31] James C. Bonbright, Principles of Public Utility Rates at 347 (1961), https://www.raponline.org/wp-content/uploads/2023/09/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.

[32] Jim Lazar & Wilson Gonzalez, Smart Rate Design for a Smart Future at 6, 36, Regulatory Assistance Project (July 2015), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[33] Bonbright, *supra* n.31 at 347.

[34] *See* Williams Direct at 14, et seq.

[35] Bonbright, Principles of Public Utility Rates, *supra* n.31 at 347–49.

[36] Jim Lazar, Paul Chernick, & William Marcus, Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project (Jan. 2020), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

[37] *Id.* at 146–148 (citations omitted).

[38] *Id.*

[39] Frederick Weston, Charging for Distribution Utility Services: Issues in Rate Design at 30 (Dec. 2000) (citing the "basic customer" method as the method in use in more than 30 states), https://www.raponline.org/wp-content/uploads/2023/09/rap-weston-chargingfordistributionutilityservices-2000-12.pdf.

[40] Lazar, Chernick, & Marcus, *supra* n.36 at 145, n.141–48 and accompanying text.

[41] As such, there is no validity in rate making by alliteration, as proposed in the so-called "straight fixed-variable method" which promotes fixed charges for fixed costs.

[42] Williams Direct at 14.

[43] TECO Resp. to FL Rising/LULAC INT 78.

[44] *Id.*

[45] TECO Petition for Rate Increase at 6, ¶ 15.

[46] TECO witness Jeff Chronister direct testimony ("Chronister Direct") at 4.

[47] TECO witness Dylan W. D'Ascendis direct testimony ("D'Ascendis Direct").

[48] *Id.*

[49] Collins Direct at 31.

[50] Edison Electric Institute ("EEI"), *Electric Company Industry Financial Data and Analysis – Rate Review Data* (2023 Q4), https://www.eei.org/issues-and-policy/finance-and-tax.

[51] *Id.*

[52] TECO Resp. to FL Rising/LULAC INT 103.

[53] Christopher Rugaber, *Fed Powell Suggests Taming Inflation Will Take Longer Than Expected,* PBS NewsHour (May 1, 2024), https://www.pbs.org/newshour/economy/watch-live-fed-chair-powell-holds-news-conference-following-interest-rate-meeting.

[54] As of 2024, TECO is 88% dependent on fossil fuels for generation, with the remainder coming from utility-scale solar generation. Collins Direct at 18.

[55] TECO Resp. to FL Rising/LULAC INT 53.

[56] *Id.* at 53.d.

[57] The Wikipedia entry related to the so-called "Ramsey Problem" explains this approach as follows: "The Ramsey problem, or Ramsey pricing, or Ramsey–Boiteux pricing, is a second-best policy problem concerning what prices a public monopoly should charge for the various products it sells in order to maximize social welfare (the sum of producer and consumer surplus) while earning enough revenue to cover its fixed costs. Under Ramsey pricing, the price markup over marginal cost is inverse to the price elasticity of demand and the price elasticity of supply: the more elastic the product's demand or supply, the smaller the markup." Wikipedia, *Ramsey Problem*, https://en.wikipedia.org/wiki/Ramsey_problem (last visted June 4, 2024).

[58] TECO Resp. to FL Rising/LULAC INT 4.a.

[59] *See* TECO TECO Resp. to FL Rising/LULAC INT 8.

[60] *See* TECO witness Marian Cacciatorre direct testimony ("Cacciatorre Direct"); TECO Resp. to OPC POD 1-30 (BS pages 13178–13249); TECO Resp. to FL Rising/LULAC INT 96–99.

[61] *See* TECO Resp. to FL Rising/LULAC INT 115–17.

[62] TECO witness Jose Aponte direct testimony ("Aponte Direct") at 7–8; TECO Resp. to FL Rising/LULAC INT 95.

[63] TECO Resp. to OPC POD 1-30 (BS pages 13178–13249). TECO typically weights net income goal achievement at 35% of the total incentive compensation package.

[64] TECO witness Carlos Aldazabal direct testimony ("Aldazabal Direct") at 46–50.

[65] TECO Resp. to FIPUG INT 1.

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Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a regulatory expert, utility executive, research and development manager, sustainability leader, senior government official, educator, and advocate. Law teaching experience at Pace University Elisabeth Haub School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing business sustainability, expert witness, and regulatory advice and services to organizations in the clean and advanced energy sectors. Prepared and submitted testimony in more than 35 jurisdictions and 165 electricity and gas regulatory proceedings. Recognized national leader in development and implementation of innovative "Value of Solar" alternative to traditional net metering. Additional information at rabagoenergy.com.

- Director, Colorado Electric Transmission Authority (2022-present).
- Chairman of the Board, Center for Resource Solutions (1997-present). Past chair of the Green-e Governance Board.
- Director, Solar United Neighbors (2018-present).
- Advisor, Commission Shift (2021-present).
- Director, Texas Solar Energy Society (2022-present).

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Senior Policy Advisor: September 2019—September 2020. Part-time advisor and staff member. Provided transitional expert witness, project management, and business development support on electric and gas regulatory and policy issues and activities.

Executive Director: May 2014—August 2019. Leader of a team of professional and technical experts and law students in energy and climate law, policy, and regulation. Secured funding for and managed execution of regulatory intervention, research, market development support, and advisory services. Taught Energy Law. Provided learning and development opportunities for law students. Additional activities:

- Director, Alliance for Clean Energy – New York (2018-2019).
- Director, Interstate Renewable Energy Council (IREC) (2012-2018).
- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017). The NESEMC was a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC worked to harmonize solar market policy and advance supportive policy and regulatory practices in the northeast United States.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in one of the largest public power electric utilities, serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Member, Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Director, Global Regulatory Affairs, provided regulatory support and group management to AES's international electric utility operations on five continents. Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE Energy and AES venture committed to generating and marketing voluntary market greenhouse gas credits. Government and regulatory affairs manager for AES Wind Generation. Managed a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008. Located in New Mexico, the JANUA was an independent utility developing profitable and autonomous utility services that provided natural gas, water utility services, low-income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan with support from U.S. Department of Energy.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining, and expanding on technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications; the Gulf Coast Combined Heat and Power Application Center; and the High-Performance Green Buildings Practice. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector.

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, led and managed successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative as an umbrella structure for multiple biofuels related projects.

- Member, Committee to Study the Environmental Impacts of Wind Power, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Integrated sustainability principles into all aspects of a ground-breaking bio-based polymer manufacturing venture. Responsible for maintaining, enhancing, and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives.

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Managed, coordinated, and developed international agreements. Supervised development and deployment support activities at national laboratories. Developed, advocated, and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT).

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-2019. Non-tenured member of faculty. Taught Energy Law. Supervised a student intern practice.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York, on federal regulation of cooling water intake structures for electric power plants.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Selected Publications

The Future of Decentralized Electricity Distribution Networks: Ch. 14 – Performance-Based Regulation to Drive Transformation and Encourage DER Market Growth, contributing co-author with Jesse Hitchcock, Elsevier (2023).

Climate Change Law: An Introduction, contributing author (Introduction to Energy Law), Elgar (2021).

Distributed Generation Law, contributing author, American Bar Association Environment, Energy, and Resources Section (August 2020)

National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, contributing author, National Energy Screening Project (August 2020)

Achieving 100% Renewables: Supply-Shaping through Curtailment, with Richard Perez, Marc Perez, and Morgan Putnam, PV Tech Power, Vol. 19 (May 2019).

A Radical Idea to Get a High-Renewable Electric Grid: Build Way More Solar and Wind than Needed, with Richard Perez, The Conversation, online at http://bit.ly/2YjnM15 (May 29, 2019).

Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition, with John Howat, John Colgan, Wendy Gerlitz, and Melanie Santiago-Mosier, National Consumer Law Center, online at www.nclc.org (Feb. 26, 2019).

Revisiting Bonbright's Principles of Public Utility Rates in a DER World, with Radina Valova, The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018).

Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators, with Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

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Jicarilla Apache Nation Utility Authority Strategic Plan for Energy Efficiency and Renewable Energy Development, lead author & project manager, U.S. Department of Energy First Steps Toward Developing Renewable Energy and Energy Efficiency on Tribal Lands Program (2008)

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A Strategy for Developing Stationary Biodiesel Generation, Cumberland Law Review, Vol. 36, p.461 (2006)

Evaluating Fuel Cell Performance through Industry Collaboration, co-author, Fuel Cell Magazine (2005)

Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production, co-author, Polymer Degradation and Stability 80, 403-19 (2003)

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Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado, with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

Study of Electric Utility Restructuring in Alaska, with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

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The Green-e Program: An Opportunity for Customers, with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

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Information Technology, Public Utilities Fortnightly (March 15, 1996)

Better Decisions with Better Information: The Promise of GIS, with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

The Regulatory Environment for Utility Energy Efficiency Programs, Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

An Alternative Framework for Low-Income Electric Ratepayer Services, with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

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Environmental Costs of Electricity, Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

Testimony Submitted by Karl R. Rábago
(as of 31 May 2024)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia State Corporation Commission Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia Public Service Commission Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 2013	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana Public Service Commission Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan Public Utilities Commission Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan Public Utilities Commission Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia Public Service Commission Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia Public Service Commission Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia State Corporation Commission Case # PUE-2013-00088	Environmental Respondents
Apr. 25, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case - Direct	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jun. 2, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case – Response (Corrected)	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jun. 20, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case – Rebuttal	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal	Florida Public Service Commission Docket #	Southern Alliance for Clean Energy

	Setting – FPL, Duke, TECO, Gulf	130199-EI, 130200-EI, 130201-EI, 130202-EI	
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri Public Service Commission File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia State Corporation Commission Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)
Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin Public Service Commission Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin Public Service Commission Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin Public Service Commission Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Jan. 28, 2016 (date of CPUC order)	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California Public Utilities Commission Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York Public Service Commission Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan Public Service Commission Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i Public Utilities Commission Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisconsin Public Service Company Rate Application	Wisconsin Public Service Commission Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	Virginia State Corporation Commission Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York Public Service Commission Cases 15-E-0283, -0285	Pace Energy and Climate Center
Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida Public Service Commission Case 150196-EI	Environmental Confederation of Southwest Florida

Oct. 27, 2015	Appalachian Power Company 2015 IRP	Virginia State Corporation Commission Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island Public Utilities Commission Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay
Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center
Jan. 22, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case	Indiana Utility Regulatory Commission Cause No. 44688	Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case – Settlement Testimony	Indiana Utility Regulatory Commission Cause No. 44688	Joint Intervenors – Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Comments on Pilot Rate Proposals by MidAmerican and Alliant	Iowa Utility Board NOI-2014-0001	Environmental Law and Policy Center
May 27, 2016	Consolidated Edison of New York Rate Case	New York Public Service Commission Case No. 16-E-0060	Pace Energy and Climate Center
Jun. 21, 2016	Federal Trade Commission: Workshop on Competition and Consumer Protection Issues in Solar Energy - Invited workshop presentation	Federal Trade Commission - Solar Electricity Project No. P161200	Pace Energy and Climate Center
Aug. 17, 2016	Dominion Virginia Electric Power 2016 IRP	Virginia State Corporation Commission Case # PUE-2016-00049	Environmental Respondents
Sep. 13, 2016	Appalachian Power Company 2016 IRP	Virginia State Corporation Commission Case # PUE-2016-00050	Environmental Respondents

Oct. 27, 2016	Consumers Energy PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18090	Environmental Law & Policy Center, "Joint Intervenors"
Oct. 28, 2016	Delmarva, PEPCO (PHI) Utility Transformation Filing – Review of Filing & Utilities of the Future Whitepaper	Maryland Public Service Commission Case PC 44	Public Interest Advocates
Dec. 1, 2016	DTE Electric Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18091	Environmental Law & Policy Center, "Joint Intervenors"
Dec. 16, 2016	Development of New Alternative Net Metering Tariffs - Rebuttal of Unitil Testimony	New Hampshire Public Utilities Commission Docket No. DE 16-576	New Hampshire Sustainable Energy Association ("NHSEA")
Jan. 13, 2017	Gulf Power Company Rate Case	Florida Public Service Commission Docket No. 160186-EI	Earthjustice, Southern Alliance for Clean Energy, League of Women Voters-Florida
Jan. 13, 2017	Alpena Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18089	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Indiana Michigan Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18092	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Northern States Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18093	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Upper Peninsula Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18094	Environmental Law & Policy Center, "Joint Intervenors"
Mar. 10, 2017	Eversource Energy Grid Modernization Plan	Massachusetts Department of Public Utilities Case No. 15-122/15-123	Cape Light Compact
Apr. 27, 2017	Eversource Rate Case & Grid Modernization Investments	Massachusetts Department of Public Utilities Case No. 17-05	Cape Light Compact
May 2, 2017	AEP Ohio Power Electric Security Plan	Public Utilities Commission of Ohio Case No. 16-1852-EL-SSO	Environmental Law & Policy Center
Jun. 2, 2017	Vectren Energy TDSIC Plan	Indiana Utility Regulatory Commission Cause No. 44910	Citizens Action Coalition & Valley Watch
Jul. 26, 2017	Vectren Energy 2018-2020 Energy Efficiency Plan	Indiana Utility Regulatory Commission Cause No. 44927	Citizens Action Coalition
Jul. 28, 2017	Vectren Energy 2016-2017 Energy Efficiency Plan	Indiana Utility Regulatory Commission Cause No. 44645	Citizens Action Coalition

Aug. 1, 2017	Interstate Power & Light (Alliant) 2017 Rate Application	Iowa Utilities Board Docket No. RPU-2017-0001	Environmental Law & Policy Center, Iowa Environmental Council, Natural Resources Defense Council, and Solar Energy Industries Assoc.
Aug. 11, 2017	Dominion Virginia Electric Power 2017 IRP	Virginia State Corporation Commission Case # PUR-2017-00051	Environmental Respondents
Aug. 18, 2017	Appalachian Power Company 2017 IRP	Virginia State Corporation Commission Case # PUR-2017-00045	Environmental Respondents
Aug. 23, 2017	Pennsylvania Solar Future Project	Pennsylvania Dept. of Environmental Protection - Alternative Ratemaking Webinar	Pace Energy and Climate Center
Aug. 25, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York Public Service Commission Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Sep. 15, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York Public Service Commission Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Oct. 20, 2017	Missouri PSC Working Case to Explore Emerging Issues in Utility Regulation	Missouri Public Service Commission File No. EW-2017-0245	Renew Missouri
Nov. 21, 2017	Central Hudson Gas & Electric Co. Electric and Gas Rates Cases	New York Public Service Commission Case # 17-E-0459, -0460	Pace Energy and Climate Center
Jan. 16, 2018	Great Plains Energy, Inc. Merger with Westar Energy, Inc.	Missouri Public Service Commission Case # EM-2018-0012	Renew Missouri Advocates
Jan. 19, 2018	U.S. House of Representatives, Energy and Commerce Committee	Hearing on "The PURPA Modernization Act of 2017," H.R. 4476	Rábago Energy LLC
Jan. 29, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts Department of Public Utilities Case No. 17-140	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Feb. 21, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts Department of Public Utilities Case No. 17-140 - Surrebuttal	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Apr. 6, 2018	Narragansett Electric Co., d/b/a National Grid Rate Case Filing	Rhode Island Public Utilities Commission Docket No. 4770	New Energy Rhode Island ("NERI")

Apr. 25, 2018	Narragansett Electric Co., d/b/a National Grid Power Sector Transformation Plan	Rhode Island Public Utilities Commission Docket No. 4780	New Energy Rhode Island ("NERI")
Apr. 26, 2018	U.S. EPA Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Stories: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (Oct. 16, 2017) – "Clean Power Plan"	U.S. Environmental Protection Agency Docket No. EPA-HQ-OAR-2016-0592	Karl R. Rábago
May 25, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York Public Service Commission Case Nos. 18-E-0067, 18-G-0068	Pace Energy and Climate Center
Jun. 15, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York Public Service Commission Case Nos. 18-E-0067, 18-G-0068 – Rebuttal Testimony	Pace Energy and Climate Center
Aug. 10, 2018	Dominion Virginia Electric Power 2018 IRP	Virginia State Corporation Commission Case # PUR-2018-00065	Environmental Respondents
Sep. 20, 2018	Consumers Energy Company Rate Case	Michigan Public Service Commission Case No. U-20134	Environmental Law & Policy Center
Sep. 27, 2018	Potomac Electric Power Co. Notice to Construct Two 230 kV Underground Circuits	District of Columbia Public Service Commission Formal Case No. 1144	Solar United Neighbors of D.C.
Sep. 28, 2019	Arkansas Public Service Commission Investigation of Policies Related to Distributed Energy Resources	Arkansas Public Service Commission Docket No. 16-028-U	Arkansas Audubon Society & Arkansas Advanced Energy Association
Nov. 7, 2018	DTE Detroit Edison Rate Case	Michigan Public Service Commission Case No. U-20162	Natural Resources Defense Council, Michigan Environmental Council, Sierra Club
Mar. 26, 2019	Guam Power Authority Petition to Modify Net Metering	Guam Public Utilities Commission Docket GPA 19-04	Micronesia Renewable Energy, Inc.
Apr. 4, 2019	Community Power Network & League of Women Voters of Florida v. JEA	Circuit Court Duval County of Florida Case No. 2018-CA-002497 Div: CV-D	Earthjustice
Apr. 16, 2019	Dominion Virginia Electric Power 2018 IRP – Compliance Filing	Virginia State Corporation Commission Case # PUR-2018-00065	Environmental Respondents
Apr. 25, 2019	Georgia Power 2019 IRP	Georgia Public Service Commission Docket No. 42310	GSEA & GSEIA

May 10, 2019	NV Energy NV GreenEnergy 2.0 Rider	Nevada Public Utilities Commission Docket Nos. 18-11015, 18-11016	Vote Solar
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Misc. Issues	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Low- and Moderate-Income Panel	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 30, 2019	Connecticut DEEP Shared Clean Energy Facility Program Proposal	Connecticut Department of Energy and Environmental Protection Docket No. 19-07-01	Connecticut Fund for the Environment
Jun. 3, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Jun. 14, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Rebuttal Testimony	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
Jun. 24, 2019	Program to Encourage Clean Energy in Westchester County Pursuant to Public Service law Section 74-a; Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory	New York Public Service Commission Case Nos. 19-M-0265, 19-G-0080	Earthjustice and Pace Energy and Climate Center
Jul. 12, 2019	Application of Virginia Electric and Power Company for the Determination of the Fair Rate of Return on Common Equity	Virginia State Corporation Commission Case # PUR-2019-00050	Virginia Poverty Law Center
Jul. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Reply Comments	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Aug. 1, 2019	Interstate Power and Light Company – General Rate Case	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Aug. 19, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Surrebuttal	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
Aug. 21, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29	Connecticut Fund for the Environment and Save Our Sound

	- Comments		
Sep. 10, 2019	Interstate Power and Light Company – General Rate Case - Rebuttal	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Sep. 18, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Comments and Response to Draft Study Outline	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29	Connecticut Fund for the Environment, Save Our Sound, E4theFuture, NE Clean Energy Council, NE Energy Efficiency Partnership, and Acadia Center
Sep. 20, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 1	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16715	Connecticut Fund for the Environment and Save Our Sound
Oct. 4, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 2	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16766	Connecticut Fund for the Environment and Save Our Sound
Oct. 15, 2019	Electronic Consideration of the Implementation of the Net Metering Act (KY SB 100)	Kentucky Public Service Commission Case No. 2019-00256	Kentuckians for the Commonwealth & Mountain Association for Community Economic Development
Oct. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Comments on City Council Utility Advisors' Report	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana, Vote Solar, 350 New Orleans, Alliance for Clean Energy, PosiGen, and Sierra Club
Oct. 17, 2019	Indiana Michigan Power Co. General Rate Case	Michigan Public Service Company Case No. U-20359	Environmental Law & Policy Center, The Ecology Center, the Solar Energy Industries Association, and Vote Solar
Dec. 4, 2019	Alabama Power Company Petition for Certificate of Convenience and Necessity	Alabama Public Service Commission Docket No. 32953	Energy Alabama and Gasp, Inc.
Dec. 5, 2019	In the Matter of Net Metering and the Implementation of Act 827 of 2015	Arkansas Public Service Commission Docket No. 16-027-R	National Audubon Society and Arkansas Advanced Energy Association

Dec. 6, 2019	Proposed Revisions to Vermont Public Utility Commission Rule 5.100	Vermont Public Utility Commission Case No. 19-0855-RULE	Renewable Energy Vermont ("REV")
Jan. 15, 2020	Puget Sound Energy General Rate Case	Washington Utilities and Transportation Commission Docket Nos. UE-190529 & UG-190530	Puget Sound Energy
Feb. 11, 2020	Application of Entergy Arkansas, LLC for a Proposed Tariff Amendment: Solar Energy Purchase Option – Direct Testimony	Arkansas Public Service Commission Docket No. 19-042-TF	Arkansas Advanced Energy Association
Mar. 17, 2020	Application of Entergy Arkansas, LLC for a Proposed Tariff Amendment: Solar Energy Purchase Option – Surrebuttal Testimony	Arkansas Public Service Commission Docket No. 19-042-TF	Arkansas Advanced Energy Association
Jun. 16, 2020	PECO Energy Default Supply Plan V – Direct Testimony	Pennsylvania Public Utility Commission Docket No. P-2020-3019290	Environmental Respondents / Earthjustice
Jun. 24, 2020	Consumers Energy Company General Rate Case – Direct Testimony	Michigan Public Service Commission Case No. U-20697	Joint Clean Energy Organizations / Environmental Law & Policy Center
Jul. 14, 2020	Consumers Energy Company General Rate Case – Rebuttal Testimony	Michigan Public Service Commission Case No. U-20697	Joint Clean Energy Organizations / Environmental Law & Policy Center
Jul. 23, 2020	PECO Energy Default Supply Plan V – Surrebuttal Testimony	Pennsylvania Public Utility Commission Docket No. P-2020-3019290	Environmental Stakeholders / Earthjustice
Sep. 15, 2020	Dominion Virginia Electric Power 2020 IRP – Direct Testimony	Virginia State Corporation Commission Case # PUR-2020-00035	Environmental Respondents
Sep. 18, 2020	Avoided Cost Proceeding for Georgia Power – Direct Testimony	Georgia Public Service Commission Docket No. 4822	Georgia Solar Energy Industries Association, Inc.
Sep. 29, 2020	Madison Gas and Electric – General Rate Case – Affidavit in Opposition to Electric Rates Settlement	Wisconsin Public Service Commission Docket No. 3270-UR-123	Sierra Club
Sep. 30, 2020	Madison Gas and Electric – General Rate Case – Gas Rates	Wisconsin Public Service Commission Docket No. 3270-UR-123	Sierra Club
Oct. 2, 2020	Duke Energy Florida Petition for Approval of Clean Energy Connect Program	Florida Public Service Commission Docket No. 20200176-EI	League of United Latin American Citizens of Florida
Oct. 2, 2020	Ameren Illinois – Investigation re: Calculation of Distributed Generation Rebates	Illinois Commerce Commission Docket No. 20-0389	Joint Solar Parties

Dec. 9, 2020	Arkansas – In the Matter of a Rulemaking to Adopt an Evaluation, Measurement, and Verification Protocol and Propose M&V Amendments to the Commission's Rules for Conservation and Energy Efficiency Programs; In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas	Arkansas Public Service Commission Docket Nos. 10-100-R, 13-002-U	Arkansas Advanced Energy Association
Dec. 22, 2020	Appalachian Power Company 2020 Virginia Clean Economy Act Compliance Plan	Virginia State Corporation Commission Case No. PUR-2020-00135	Environmental Respondent
Jan. 4, 2021	Dominion Virginia Electric Power Company Clean Economy Compliance Plan	Virginia State Corporation Commission Case No. PUR-2020-00134	Environmental Respondent
Feb. 5, 2021	Ameren Illinois – Investigation re: Calculation of Distributed Generation Rebates - Rebuttal	Illinois Commerce Commission Docket No. 20-0389	Joint Solar Parties
Feb. 15, 2021	Kentucky Power Company General Rate Case	Kentucky Public Service Commission Case No. 2020-00174	Joint Intervenors – Mountain Association, Kentuckians for the Commonwealth, Kentucky Solar Energy Society
Mar. 2, 2021	Dominion Virginia Electric Power Company Rider RGGI Proposal	Virginia State Corporation Commission Case No. PUR-2020-00169	Environmental Respondent
Mar. 5, 2021	Kentucky Utilities Company and Louisville Gas and Electric Company General Rate Cases	Kentucky Public Service Commission Case Nos. 2020-00349, 2020-00350	Joint Intervenors – Mountain Association, Kentuckians for the Commonwealth, Kentucky Solar Energy Society
Apr. 5, 2021	Docket to Review the Efficacy and Fairness of the Net Metering and Interconnection Rules – Comments	Mississippi Public Service Commission Docket No. 2021-AD-19	Entegrity Energy Partners, LLC & Audubon Delta / National Audubon Society
Apr. 13, 2021	Petition of Guam Power Authority for Creation of a New Energy Storage Rate – Comments of Micronesia Renewable Energy, Inc.	Guam Public Utilities Commission Docket No. 20-09	Micronesia Renewable Energy, Inc.
May 25, 2021	Petition of Episcopal Diocese of Rhode Island for Declaratory Judgment on Transmission System Costs and Related "Affected System Operator" Studies	Rhode Island Public Utility Commission Docket No. 4981	Episcopal Diocese of Rhode Island
Jun. 21, 2021	Petition for Rate Increase by Florida Power & Light Company – Direct Testimony	Florida Public Service Commission Docket No. 20210015-EI	Florida Rising, Inc., League of United Latin American Citizens of Florida, and Environmental

			Confederation of Southwest Florida, Inc.
Jun. 22, 2021	Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief	Michigan Public Service Commission Case No. U-20963	The Environmental Law and Policy Center (EPLC)
Jun. 28, 2021	Pennsylvania Public Utility Commission v. PECO Energy Company (GRC)	Pennsylvania Utility Commission Docket No. R-2021-3024601	Clean Energy Advocates
Jul. 12, 2021	Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief – Rebuttal	Michigan Public Service Commission Case No. U-20963	The Environmental Law and Policy Center (EPLC)
Jul. 28, 2021	Application of Shenandoah Valley Electric Cooperative for a General Increase in Rates	Virginia State Corporation Commission Case No. PUR-2021-00054	Solar United Neighbors of Virginia (SUN-VA)
Aug. 5, 2021	Kentucky Utilities Company and Louisville Gas and Electric Company General Rate Cases – Supp. Proceeding on Net Energy Metering	Kentucky Public Service Commission Case Nos. 2020-00349, 2020-00350	Joint Intervenors – Mountain Association, Kentuckians for the Commonwealth, Kentucky Solar Energy Society
Sep. 2, 2021	Madison Gas & Electric Co. – General Rate Case	Wisconsin Public Service Commission Docket No. 3270-UR-124	Sierra Club
Sep. 3, 2021	Dominion Virginia Electric Power Company – Triennial Rate Review – Direct Testimony on ROE	Virginia State Corporation Commission Case No. PUR-2020-00169	
Sep. 13, 2021	Petition for Rate Increase by Florida Power & Light Company – Settlement Testimony	Florida Public Service Commission Docket No. 20210015-EI	Florida Rising, Inc., League of United Latin American Citizens of Florida, and Environmental Confederation of Southwest Florida, Inc.
Sep. 20, 2021	Madison Gas & Electric Co. – General Rate Case – Surrebuttal Testimony	Wisconsin Public Service Commission Docket No. 3270-UR-124	Sierra Club
Sep. 27, 2021	Dakota Energy Cooperative, Inc. v. East River Electric Power Cooperative, Inc. and Basin Electric Power Cooperative – Expert Report	US. District Court, District of South Dakota (Southern Division) Case 4:20-CV-04192-LLP	Dakota Energy Cooperative, Inc.
Oct. 5, 2021	In the Matter of establishing regulations for a shared solar program pursuant to § 56-594.3 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2020-00125	Coalition for Community Solar Access

Nov. 1, 2021	Dakota Energy Cooperative, Inc. v. East River Electric Power Cooperative, Inc. and Basin Electric Power Cooperative – Surrebuttal Expert Report	US. District Court, District of South Dakota (Southern Division) Case 4:20-CV-04192-LLP	Dakota Energy Cooperative, Inc.
Nov. 16, 2021	Petition of Virginia Electric and Power Company for approval of the RPS Development Plan, approval & certification of proposed CE-2 Solar Projects pursuant to § 56-580 D and 56-46.1 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2021-00146	Appalachian Voices
Mar. 1, 2022	In the Matter of establishing regulations for a multi-family shared solar program pursuant to § 56-585.1:12 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2020-00125	Appalachian Voices
Mar. 29, 2022	Review of Duke Energy Carolina, LLC & Duke Energy Progress, LLC Joint Application for Approval of NEM Tariff Revisions and Recommendations for Investigation of Costs and Benefits of Customer-Sited Generation – Expert Report	North Carolina Utilities Commission Docket No. E-100, Sub. 180	Environmental Working Group
Mar. 30, 2022	Ameren Illinois Company Petition for Approval of Performance and Tracking Metrics Pursuant to 220 ILCS 5/16-108.188(e) – Direct Testimony	Illinois Commerce Commission Docket No. 22-0063	Joint Solar Parties
Apr. 6, 2022	Commonwealth Edison Company Petition for the Establishment of Performance Metrics under Section 16-108.18(e) of the Public Utilities Act	Illinois Commerce Commission Docket No. 22-0067	Joint Solar Parties
May 6, 2022	Review of Duke Energy Carolina, LLC & Duke Energy Progress, LLC Joint Application for Approval of NEM Tariff Revisions and Recommendations for Investigation of Costs and Benefits of Customer-Sited Generation – Reply Report	North Carolina Utilities Commission Docket No. E-100, Sub. 180	Environmental Working Group

May 25, 2022	Ameren Illinois Company Petition for Approval of Performance and Tracking Metrics Pursuant to 220 ILCS 5/16-108.188(e) – Rebuttal Testimony	Illinois Commerce Commission Docket No. 22-0063	Joint Solar Parties
May 27, 2022	Review of Duke Energy Carolina, LLC & Duke Energy Progress, LLC Joint Application for Approval of NEM Tariff Revisions and Recommendations for Investigation of Costs and Benefits of Customer-Sited Generation – Surreply Report	North Carolina Utilities Commission Docket No. E-100, Sub. 180	Environmental Working Group
Jun. 6, 2022	Commonwealth Edison Company Petition for the Establishment of Performance Metrics under Section 16-108.18(e) of the Public Utilities Act – Rebuttal Testimony	Illinois Commerce Commission Docket No. 22-0063	Joint Solar Parties
Jun. 22, 2022	In the Matter of Austin Energy Base Rate Case Filing Dated April 18, 2022	City of Austin Hearing Examiner	Sierra Club, Public Citizen, and Solar United Neighbors
Oct. 3, 2022	In the Matter of the Application of Northern States Power Company (Xcel) for Authority to Increase Rates for Electric Service in Minnesota	Minnesota Public Utilities Commission Docket No. E002/GR-21-630.	Just Solar Coalition
Oct. 13, 2022	Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin – Rebuttal	Wisconsin PSC Docket No. 9300-DR-106	Vote Solar
Oct. 21, 2022	Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin - Surrebuttal	Wisconsin PSC Docket No. 9300-DR-106	Vote Solar
Nov. 14, 2022	In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters	Public Utilities Commission of Ohio Case No. 21-637-GA-AIR	Environmental Law & Policy Center
Dec. 6, 2022	In the Matter of the Application of Northern States Power Company (Xcel) for Authority to Increase Rates for Electric Service in Minnesota - Surrebuttal	Minnesota Public Utilities Commission Docket No. E002/GR-21-630.	Just Solar Coalition

Dec. 19, 2022	Application of NorthWestern Energy for Authority to Increase Retail Electric and Natural Gas Utility Service Rates - Direct	Montana Public Service Commission Docket No. 2022.07.078	Montana Environmental Information Center (MEIC), Earthjustice
Jan. 11, 2023	Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its Operations throughout the State of Arizona and for Related Approvals – Direct Testimony on ROE & Equity Ratio	Arizona Corporation Commission Docket No. E-01933A-22-0107	Arizona Solar Energy Industries Association & Solar Energy Industries Association
Jan. 27, 2023	Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its Operations throughout the State of Arizona and for Related Approvals – Direct Testimony on Community Solar	Arizona Corporation Commission Docket No. E-01933A-22-0107	Arizona Solar Energy Industries Association & Solar Energy Industries Association
Mar. 6, 2023	Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its Operations throughout the State of Arizona and for Related Approvals – Surrebuttal Testimony	Arizona Corporation Commission Docket No. E-01933A-22-0107	Arizona Solar Energy Industries Association & Solar Energy Industries Association
May 6, 2023	The Peoples Gas Light and Coke Company – Proposed General Increase in Rates and Revisions to Service Classifications, Riders, and Terms and Conditions of Service – Direct Testimony	Illinois Commerce Commission Docket No. 23-0069	City of Chicago

July 17, 2023	The Peoples Gas Light and Coke Company – Proposed General Increase in Rates and Revisions to Service Classifications, Riders, and Terms and Conditions of Service – Rebuttal Testimony	Illinois Commerce Commission Docket No. 23-0069	City of Chicago
Aug. 25, 2023	In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise Its Terms – Direct Testimony	Maryland Public Service Commission Case No. 9704	Chesapeake Climate Action Network
Aug. 28, 2023	Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates – Direct Testimony	Public Service Commission of Wisconsin Docket No. 3270-UR-125	City of Madison
Sep. 16, 2023	Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates – Surrebuttal Testimony	Public Service Commission of Wisconsin Docket No. 3270-UR-125	City of Madison
Oct. 10, 2023	In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise Its Terms – Surrebuttal Testimony	Maryland Public Service Commission Case No. 9704	Chesapeake Climate Action Network
Apr. 16, 2024	In Re: Interstate Power & Light Company (General Rate Case) – Direct Testimony	Iowa Utilities Board Docket No. RPU-2023-0002	Clean Energy Districts of Iowa (CEDI) Coalition
Apr. 26, 2024	PECO Energy Default Supply Plan VI – Direct Testimony	Pennsylvania Public Utility Commission Docket No. P-2024-3046008	Energy Justice Advocates / Earthjustice
Apr. 30, 2024	In Re: Interstate Power & Light Company (General Rate Case) – Cross-Rebuttal Testimony	Iowa Utilities Board Docket No. RPU-2023-0002	Clean Energy Districts of Iowa (CEDI) Coalition
May 29, 2024	In Re: Interstate Power & Light Company (General Rate Case) – Surrebuttal Testimony	Iowa Utilities Board Docket No. RPU-2023-0002	Clean Energy Districts of Iowa (CEDI) Coalition

May 31, 2024	Delta States Utilities LA, LLC and Entergy Louisiana, LLC – Ex Parte; In Re: Application for Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application for Approval of Transfer and Acquisition of Local Distribution Company Assets and Related Relief	Council of the City of New Orleans Docket Number UD-24-01	Alliance for Affordable Energy

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RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

SUMMARY - CLASS ROR'S & REVENUE REQUIREMENTS -ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
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	28,068	2,473	6,196	660	129	102	118	
4										
5	TOTAL OPERATING REVENUES	1,518,472	948,672	97,688	316,679	45,013	23,924	3,673	82,823	
6										
7										
8	OPERATING EXPENSES									
9	Power Transactions	626	316	29	218	35	26	3	-	
10	O&M Expense	391,771	241,198	23,375	95,541	12,518	7,830	1,155	10,154	
11	Deprec & Amortiz Expense	531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390	
12	Taxes Other than Income	101,592	57,942	5,078	27,912	3,545	2,205	317	4,593	
13	Income Taxes	(8,327)	15,688	4,134	(27,966)	(2,804)	(3,207)	(273)	6,101	
14	Gain/(Loss) on Disposal	-	-	-	-	-	-	-	-	
15										
16	TOTAL OPERATING EXPENSES	1,017,099	615,159	59,985	244,572	32,254	18,999	2,893	43,237	
17										
18										
19	NET OPERATING INCOME	501,372	333,513	37,702	72,106	12,760	4,925	780	39,586	
20										
21										
22	RATE BASE									
23	Plant in Service	13,418,078	7,574,297	658,507	3,804,683	483,388	304,212	42,594	550,399	
24	Plant Held for Future Use	68,034	39,340	3,165	21,161	2,679	1,476	212	-	
25	Working Capital	86,671	45,968	4,053	28,019	3,980	2,761	358	1,530	
26	Construction Work in Progress	230,175	131,658	11,829	65,020	9,231	6,508	610	5,318	
27	Less: Depreciation Reserve	4,004,807	2,284,730	196,825	1,108,748	138,811	86,640	12,964	176,089	
28										
29	TOTAL RATE BASE	9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159	
30										
31										
32										
33	RATE OF RETURN (%)	5.12	6.06	7.84	2.57	3.54	2.16	2.53	10.39	
34										
35	RATE OF RETURN INDEX	1.00	1.18	1.53	0.50	0.69	0.42	0.49	2.03	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

SUMMARY - CLASS ROR'S & REVENUE REQUIREMENTS - ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
36	DEVELOPMENT OF REVENUE REQUIREMENTS									
37	Total Rate Base	9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159	
38	Total Cost of Capital	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	
39	(@ 9.50% ROE)									
40	Total Required Net Operating Income	630,021	354,070	30,911	180,692	23,178	14,681	1,981	24,509	
41										
42	Less: Achieved Net Operating Income	501,372	333,513	37,702	72,106	12,760	4,925	780	39,586	
43										
44	Equals: Return Deficiency/(Surplus)	128,649	20,557	(6,791)	108,585	10,418	9,756	1,201	(15,078)	
45	Times: Expansion Factor	1.3436	1.3436	1.3436	1.3436	1.3436	1.3436	1.3436	1.3436	
46										
47	Equals: Revenue Deficiency/ (Surplus)	172,858	27,621	(9,125)	145,900	13,998	13,108	1,614	(20,258)	
48										
49	Plus: Revenues @ Present Rates	1,518,472	948,672	97,688	316,679	45,013	23,924	3,673	82,823	
50										
51	Equals: Total Revenue Requirements	1,691,330	976,293	88,563	462,578	59,012	37,032	5,287	62,565	
52	Less: Other Revenues	(37,746)	(28,068)	(2,473)	(6,196)	(660)	(129)	(102)	(118)	
53										
54	Equals: Total Sales Revenue Requirements	1,653,583	948,225	86,090	456,382	58,351	36,903	5,185	62,448	
55										
56	Sales Revenue Requirements Index	0.90	0.97	1.11	0.68	0.76	0.64	0.69	1.32	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
COST OF SERVICE STUDY
(000's)

OPERATING REVENUES - OPREV

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
1	SALES REVENUE	REV	1,480,725	920,604	95,215	310,482	44,353	23,795	3,570	82,706	501
2											
3	MISC SERVICE REVENUE: Acct 451	CUST	18,469	16,477	1,597	391	-	-	5	-	420
4											
5	RENT REVENUE: Acct 454										
6	Production	DEM	312	169	15	102	15	11	1	-	122
7	Transmission	DEM	707	410	34	216	27	19	1	-	117
8	Subtransmission	DEM	139	81	7	43	5	4	0	-	117
9	Distribution Primary	DEM	14,488	9,018	641	4,294	452	0	83	-	105
10	Distribution Secondary	DEM	119	87	7	25	-	-	0	-	106
11	TOTAL RENT REVENUE		15,765	9,765	704	4,680	499	34	85	-	
12											
13	PLANT RELATED REVENUE: Acct 456										
14	Production	DEM	1,539	834	73	503	72	52	5	-	122
15	Production	EGY	145	73	7	51	8	6	1	-	201
16	Transmission	DEM	225	131	11	69	9	6	0	-	117
17	Transmission Firm Whsl.	REV	-	-	-	-	-	-	-	-	202
18	Subtransmission	DEM	117	68	6	36	4	3	0	-	117
19	Distribution Primary	DEM	457	285	20	135	14	0	3	-	105
20	Distribution Secondary	DEM	230	168	13	48	-	-	1	-	106
21	Distribution	CUST	216	80	12	6	0	0	0	118	907
22	Other	CUST	52	47	5	1	0	0	0	-	412
23	TOTAL PLANT RELATED REVENUE		2,981	1,685	146	848	108	68	9	118	
24											
25	ENERGY-RELATED REVENUE: Acct 456										
26	Steam & Miscellaneous	EGY	494	249	23	172	27	20	3	-	201
27	Other SO2 Whsl	EGY	-	-	-	-	-	-	-	-	202
28	Subtotal Non-Sales Revenue	SUBTOTAL	494	249	23	172	27	20	3	-	
29	Collect Fee/Sales Tax	EGY	107	54	5	37	6	4	1	-	204
30	Energy Power Sales	EGY	-	-	-	-	-	-	-	-	201
31	Unbilled Revenue	EGY	(70)	(161)	(2)	70	21	2	-	-	508
32	Subtotal Sales Revenue	SUBTOTAL	37	(107)	3	107	27	7	1	-	
33	TOTAL ENERGY RELATED REVENUE		531	142	26	278	54	27	3	-	
34											
35	TOTAL OPERATING REVENUE										
36	Sales (incl Transm Firm Whsl)	REV	1,480,725	920,604	95,215	310,482	44,353	23,795	3,570	82,706	
37	Production	DEM	1,851	1,004	87	605	87	63	6	-	
38	Production	EGY	676	216	33	329	62	33	4	-	
39	Transmission	DEM	932	540	45	285	36	26	1	-	
40	Subtransmission	DEM	256	148	12	78	10	7	0	-	
41	Distribution Primary	DEM	14,946	9,302	662	4,430	466	0	86	-	
42	Distribution Secondary	DEM	349	254	20	73	-	-	1	-	
43	Distribution	CUST	216	80	12	6	0	0	0	118	
44	Other	CUST	18,521	16,523	1,601	392	0	0	5	-	
45											
46	TOTAL OPERATING REVENUE		1,518,472	948,672	97,688	316,679	45,013	23,924	3,673	82,823	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
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(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
1	FUEL & POWER TRANSACTIONS										
2	Whsl Capacity & Reactive Pwr	DEM	-	-	-	-	-	-	-	-	201
3	Whsl NR SO 2 allowances	EGY	-	-	-	-	-	-	-	-	201
4	Whsl NRFuel Handling & Analysis	EGY	-	-	-	-	-	-	-	-	201
5											
6	Retail Reactive Power	DEM	-	-	-	-	-	-	-	-	122
7	Retail NRFuel Handling & Misc.	EGY	626	316	29	218	35	26	3	-	201
8											
9	Production Demand	DEM	-	-	-	-	-	-	-	-	
10	Production Energy	EGY	626	316	29	218	35	26	3	-	
11	TOTAL FUEL & POWER TRANSACTIONS O&M		626	316	29	218	35	26	3	-	
12											
13											
14	PRODUCTION O&M										
15	Production Demand	DEM	95,092	51,571	4,492	31,060	4,445	3,240	285	-	122
16	Production Demand - Solar	DEM	-	-	-	-	-	-	-	-	121
17	Production Energy	EGY	29,310	14,791	1,367	10,183	1,621	1,194	155	-	201
18	TOTAL PRODUCTION O&M		124,402	66,362	5,859	41,242	6,066	4,434	440	-	
19											
20											
21	TRANSMISSION O&M										
22	Step-Up Substations	DEM	3,435	1,863	162	1,122	161	117	10	-	122
23											
24	High-Volt Transmission	DEM	1,992	1,155	95	609	76	55	1	-	117
25											
26	Subtransmission										
27	Substations	DEM	4,111	2,384	197	1,257	157	113	3	-	117
28	LINES	DEM	1,477	857	71	452	56	40	1	-	117
29	Subtransmission		5,587	3,241	267	1,709	213	153	4	-	
30											
31	TOTAL TRANSMISSION O&M		11,015	6,259	525	3,440	450	325	16	-	

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(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
32	DISTRIBUTION O&M										
33	Substations	DEM	5,221	3,249	231	1,547	163	0	30	-	105
34											
35	OH LINES Direct	CUST	1,267	-	-	-	-	-	-	1,267	310
36	OH LINES Primary	DEM	19,119	11,900	846	5,667	596	0	110	-	105
37	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
38	OH LINES Secondary	DEM	4,451	3,248	262	926	-	-	16	-	106
39	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
40	TOTAL OH LINES		24,837	15,148	1,108	6,593	596	0	126	1,267	
41											
42	UG LINES Direct	CUST	3	-	-	-	-	-	-	3	310
43	UG LINES Primary	DEM	6,193	3,855	274	1,836	193	0	36	-	105
44	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
45	UG LINES Secondary	DEM	472	345	28	98	-	-	2	-	106
46	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
47	TOTAL UG LINES		6,668	4,199	302	1,934	193	0	37	3	
48											
49	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
50	Transformers Primary	DEM	50	31	2	15	2	0	0	-	105
51	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
52	Transformers Secondary	DEM	254	185	15	53	-	-	1	-	106
53	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
54	TOTAL Transformers		304	217	17	68	2	0	1	-	
55											
56	Services	CUST	4,706	4,199	407	100	-	-	1	-	420
57	Meters	CUST	9,007	6,149	1,604	1,055	87	95	18	-	308
58	Interruptible Equipment	CUST	-	-	-	-	-	-	-	-	309
59	Street Lighting	CUST	3,452	-	-	-	-	-	-	3,452	310
60											
61	Distribution O&M	DEM	35,760	22,813	1,658	10,142	953	0	194	-	
62	Distribution O&M	CUST	18,435	10,348	2,010	1,155	87	95	19	4,721	
63											
64	TOTAL DISTRIBUTION O&M		54,195	33,161	3,669	11,296	1,040	95	214	4,721	
65											
66											
67	PROD, TRANS & DIST O&M										
68	Production	DEM	98,527	53,434	4,654	32,182	4,605	3,357	295	-	
69	Production	EGY	29,310	14,791	1,367	10,183	1,621	1,194	155	-	
70	Transmission	DEM	1,992	1,155	95	609	76	55	1	-	
71	Subtransmission	DEM	5,587	3,241	267	1,709	213	153	4	-	
72	Distribution Primary	DEM	30,582	19,035	1,354	9,065	953	0	176	-	
73	Distribution Secondary	DEM	5,178	3,778	304	1,077	-	-	19	-	
74	Distribution	CUST	18,435	10,348	2,010	1,155	87	95	19	4,721	
75	Other	CUST	-	-	-	-	-	-	-	-	
76	TOTAL PROD, TRANS & DIST O&M		189,612	105,781	10,052	55,979	7,556	4,853	669	4,721	

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TAMPA ELECTRIC COMPANY
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(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
77	PLUS: OTHER CUSTOMER O&M										
78	Uncollectible	CUST	5,797	3,604	373	1,215	174	93	14	324	507
79	Billing & Records	CUST	29,377	26,201	2,540	626	2	0	8	-	412
80	Meter Reading	CUST	4,394	3,897	382	111	2	1	3	-	311
81	Cust Svc & Info	CUST	5,165	4,607	447	110	0	0	1	-	412
82	Sales	CUST	312	278	27	7	0	0	0	-	412
83	TOTAL OTHER CUSTOMER O&M		45,044	38,586	3,768	2,068	178	94	27	324	
84											
85	PLUS: ADMIN & GENERAL O&M (EXCL STORM ACCRUAL)										
86	Production	DEM	57,915	31,409	2,736	18,917	2,707	1,973	174	-	122
87	Production - Solar	DEM	3,180	1,725	150	1,039	149	108	10	-	121
88	Production	EGY	12,296	6,205	573	4,272	680	501	65	-	201
89	Transmission	DEM	1,647	955	79	504	63	45	1	-	117
90	Subtransmission	DEM	5,533	3,209	265	1,692	211	152	4	-	117
91	Distribution Primary	DEM	28,200	17,552	1,248	8,358	879	0	162	-	105
92	Distribution Secondary	DEM	4,599	3,356	270	957	-	-	17	-	106
93	Distribution	CUST	19,947	11,197	2,175	1,249	94	102	21	5,109	607
94	Other	CUST	23,797	21,224	2,057	507	2	0	7	-	412
95	TOTAL ADMIN & GENERAL O&M		157,115	96,832	9,555	37,494	4,785	2,882	459	5,109	
96											
97	PLUS: ADMIN & GENERAL (STORM ACCRUAL ONLY)										
98	Production	DEM	-	-	-	-	-	-	-	-	122
99	Production	EGY	-	-	-	-	-	-	-	-	204
100	Transmission	DEM	-	-	-	-	-	-	-	-	817
101	Subtransmission	DEM	-	-	-	-	-	-	-	-	817
102	Distribution Primary	DEM	-	-	-	-	-	-	-	-	105
103	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
104	Distribution	CUST	-	-	-	-	-	-	-	-	607
105	Other	CUST	-	-	-	-	-	-	-	-	412
106	TOTAL ADMIN & GENERAL STORM ACCRUAL		-	-	-	-	-	-	-	-	
107	SUBTOTAL ADMIN & GENERAL O&M		157,115	96,832	9,555	37,494	4,785	2,882	459	5,109	
108											
109	EQUALS: O&M EXP LESS FUEL & POWER TRANS										
110	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-	
111	Production	EGY	41,606	20,996	1,940	14,454	2,301	1,695	220	-	
112	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-	
113	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-	
114	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-	
115	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-	
116	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830	
117	Other	CUST	68,841	59,810	5,825	2,575	180	94	33	324	
118											
119	TOTAL O&M EXPENSE (EXCL. FUEL & POWER TRANS.)		391,771	241,198	23,375	95,541	12,518	7,830	1,155	10,154	
120											
121	EQUALS: O&M EXP PLUS FUEL & POWER TRANS										
122	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-	
123	Production	EGY	42,233	21,312	1,969	14,672	2,336	1,721	223	-	
124	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-	
125	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-	
126	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
127	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-	
128	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830	
129	Other	CUST	68,841	59,810	5,825	2,575	180	94	33	324	
130	TOTAL O&M EXPENSE (INCL. FUEL & POWER TRANS.)		392,398	241,514	23,404	95,759	12,553	7,855	1,159	10,154	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION DEPREC EXPENSE										
2	Production Demand	DEM	190,419	103,269	8,995	62,196	8,900	6,488	571	-	122
3	Production Demand - Solar Facilities	DEM	70,700	38,342	3,340	23,093	3,305	2,409	212	-	121
4	Production Energy	EGY	24,172	12,198	1,127	8,397	1,337	985	128	-	201
5	TOTAL PRODUCTION DEPRE EXPENSE		285,292	153,809	13,462	93,687	13,542	9,881	910	-	
6											
7											
8	TRANSMISSION DEPREC EXPENSE										
9	Step-Up Substations	DEM	4,400	2,386	208	1,437	206	150	13	-	122
10	Step-Up Substations - Solar	DEM	-	-	-	-	-	-	-	-	121
11	Step-Up Substations		4,400	2,386	208	1,437	206	150	13	-	
12											
13	High-Volt Transmission	DEM	13,062	7,576	625	3,995	499	358	9	-	117
14											
15	Subtransmission										
16	Substations	DEM	5,099	2,958	244	1,560	195	140	4	-	117
17	LINES	DEM	7,611	4,415	364	2,328	291	209	5	-	117
18	Subtransmission		12,711	7,372	608	3,888	485	348	9	-	
19											
20	TOTAL TRANSMISSION DEPREC EXPENSE		30,172	17,334	1,441	9,319	1,190	856	31	-	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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(000's)

DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
21	DISTRIBUTION DEPREC EXPENSE										
22	Substations	DEM	9,807	6,104	434	2,907	306	0	56	-	105
23											
24	Poles Direct	CUST	2,045	-	-	-	-	-	-	2,045	310
25	Poles Primary	DEM	19,187	11,943	849	5,687	598	0	110	-	105
26	Poles Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
27	Poles Secondary	DEM	5,762	4,204	339	1,199	-	-	21	-	106
28	Poles Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
29	TOTAL POLES		26,995	16,147	1,188	6,886	598	0	131	2,045	
30											
31	OH LINES Direct	CUST	107	-	-	-	-	-	-	107	310
32	OH LINES Primary	DEM	5,930	3,691	263	1,758	185	0	34	-	105
33	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
34	OH LINES Secondary	DEM	902	658	53	188	-	-	3	-	106
35	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
36	TOTAL OH LINES		6,939	4,349	316	1,945	185	0	37	107	
37											
38	UG LINES Direct	CUST	10	-	-	-	-	-	-	10	310
39	UG LINES Primary	DEM	19,824	12,339	878	5,876	618	0	114	-	105
40	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
41	UG LINES Secondary	DEM	1,512	1,103	89	314	-	-	5	-	106
42	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
43	TOTAL UG LINES		21,346	13,442	966	6,190	618	0	119	10	
44											
45	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
46	Transformers Primary	DEM	6,446	4,012	285	1,911	201	0	37	-	105
47	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
48	Transformers Secondary	DEM	32,749	23,895	1,924	6,812	-	-	118	-	106
49	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
50	TOTAL Transformers		39,195	27,907	2,209	8,722	201	0	155	-	
51											
52	Services	CUST	5,783	5,159	500	122	-	-	1	-	420
53	Meters	CUST	15,404	10,516	2,742	1,804	148	162	31	-	308
54	Installations on Customers' Premises	CUST	-	-	-	-	-	-	-	-	309
55	Street Lighting	CUST	15,232	-	-	-	-	-	-	15,232	310
56											
57	Total Distribution Expense										
58	Distribution Expense	DEM	102,120	67,949	5,113	26,651	1,908	0	499	-	
59	Distribution Expense	CUST	38,580	15,675	3,242	1,927	148	162	33	17,393	
60											
61	TOTAL DISTRIBUTION DEPREC EXPENSE		140,700	83,624	8,356	28,577	2,056	162	532	17,393	
62											

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
63	PROD, TRANS & DIST DEPREC EXPENSE										
64	Production	DEM	265,519	143,997	12,543	86,726	12,411	9,047	796	-	
65	Production	EGY	24,172	12,198	1,127	8,397	1,337	985	128	-	
66	Transmission	DEM	13,062	7,576	625	3,995	499	358	9	-	
67	Subtransmission	DEM	12,711	7,372	608	3,888	485	348	9	-	
68	Distribution Primary	DEM	61,195	38,089	2,709	18,138	1,908	0	351	-	
69	Distribution Secondary	DEM	40,925	29,860	2,404	8,512	-	-	148	-	
70	Distribution	CUST	38,580	15,675	3,242	1,927	148	162	33	17,393	
71	Other	CUST	-	-	-	-	-	-	-	-	
72											
73	TOTAL PROD, TRANS & DIST DEPREC EXP		456,163	254,767	23,259	131,583	16,788	10,899	1,473	17,393	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
74	PLUS: COMMUNICATION EQP DEPREC EXP										
75	Production	DEM	2,270	1,231	107	741	106	77	7	-	122
76	Production	EGY	564	285	26	196	31	23	3	-	201
77	Transmission	DEM	400	232	19	122	15	11	0	-	117
78	Subtransmission	DEM	322	187	15	99	12	9	0	-	117
79	Distribution Primary	DEM	2,079	1,294	92	616	65	0	12	-	105
80	Distribution Secondary	DEM	676	493	40	141	-	-	2	-	106
81	Distribution	CUST	801	295	45	22	1	2	0	436	907
82	Other	CUST	1,085	968	94	23	0	0	0	-	412
83											
84	TOTAL COMMUNICATION EQP DEPREC EXP		8,198	4,985	438	1,960	231	122	25	436	
85											
86	PLUS: TRANSPORTATION EQP DEPREC EXP										
87	Production	DEM	428	232	20	140	20	15	1	-	122
88	Production	EGY	-	-	-	-	-	-	-	-	201
89	Transmission	DEM	-	-	-	-	-	-	-	-	117
90	Subtransmission	DEM	-	-	-	-	-	-	-	-	117
91	Distribution Primary	DEM	-	-	-	-	-	-	-	-	105
92	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
93	Distribution	CUST	-	-	-	-	-	-	-	-	907
94	Other	CUST	-	-	-	-	-	-	-	-	412
95											
96	TOTAL TRANSPORTATION EQP DEPREC EXP		428	232	20	140	20	15	1	-	
97											
98	PLUS: GENERAL & INTANGIBLE DEPREC EXP										
99	Production	DEM	22,182	12,030	1,048	7,245	1,037	756	66	-	122
100	Production - Solar	DEM	152	83	7	50	7	5	0	-	121
101	Production	EGY	5,896	2,976	275	2,048	326	240	31	-	201
102	Transmission	DEM	885	513	42	271	34	24	1	-	117
103	Subtransmission	DEM	2,488	1,443	119	761	95	68	2	-	117
104	Distribution Primary	DEM	13,067	8,133	578	3,873	407	0	75	-	105
105	Distribution Secondary	DEM	2,254	1,645	132	469	-	-	8	-	106
106	Distribution	CUST	8,376	3,088	468	226	15	16	4	4,560	907
107	Other	CUST	11,346	10,119	981	242	1	0	3	-	412
108											
109	TOTAL GENERAL & INTANGIBLE DEPREC EXP		66,647	40,030	3,652	15,185	1,922	1,110	190	4,560	
110											
111	EQUALS: DEPRECIATION EXPENSE										
112	Production	DEM	290,552	157,573	13,726	94,902	13,581	9,899	871	-	
113	Production	EGY	30,632	15,458	1,429	10,642	1,694	1,248	162	-	
114	Transmission	DEM	14,347	8,321	686	4,388	548	393	10	-	
115	Subtransmission	DEM	15,521	9,002	743	4,747	593	425	11	-	
116	Distribution Primary	DEM	76,341	47,516	3,379	22,628	2,380	0	438	-	
117	Distribution Secondary	DEM	43,855	31,998	2,576	9,122	-	-	159	-	
118	Distribution	CUST	47,757	19,058	3,756	2,174	164	179	37	22,390	
119	Other	CUST	12,431	11,087	1,075	265	1	0	3	-	
120											
121	TOTAL DEPRECIATION EXPENSE		531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390	

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TAXES OTHER THAN INCOME TAXES - TXOTH

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PAYROLL TAXES										
2	Production	DEM	5,464	2,963	258	1,785	255	186	16	-	122
3	Production - Solar	DEM	-	-	-	-	-	-	-	-	121
4	Production	EGY	1,443	728	67	501	80	59	8	-	201
5	Transmission	DEM	217	126	10	66	8	6	0	-	117
6	Subtransmission	DEM	609	353	29	186	23	17	0	-	117
7	Distribution Primary	DEM	3,197	1,990	142	948	100	0	18	-	105
8	Distribution Secondary	DEM	551	402	32	115	-	-	2	-	106
9	Distribution	CUST	2,049	755	115	55	4	4	1	1,116	907
10	Other	CUST	2,776	2,476	240	59	0	0	1	-	412
11	TOTAL PAYROLL TAXES		16,305	9,793	893	3,715	470	271	47	1,116	
12											
13	PLUS: PROPERTY TAXES										
14	Production	DEM	45,179	24,502	2,134	14,757	2,112	1,539	135	-	122
15	Production	EGY	4,255	2,147	198	1,478	235	173	22	-	201
16	Transmission	DEM	3,319	1,925	159	1,015	127	91	2	-	117
17	Subtransmission	DEM	3,461	2,007	166	1,059	132	95	2	-	117
18	Distribution Primary	DEM	13,502	8,404	598	4,002	421	0	78	-	105
19	Distribution Secondary	DEM	6,720	4,903	395	1,398	-	-	24	-	106
20	Distribution	CUST	6,322	2,331	354	170	11	12	3	3,441	907
21	Other	CUST	1,533	1,367	133	33	0	0	0	-	412
22	TOTAL PROPERTY TAXES		84,291	47,586	4,136	23,912	3,038	1,910	268	3,441	
23											
24											
25	PLUS: OTHER TAXES										
26	Production	DEM	(76)	(41)	(4)	(25)	(4)	(3)	(0)	-	122
27	Production	EGY	(6)	(3)	(0)	(2)	(0)	(0)	(0)	-	201
28	Transmission	DEM	(6)	(3)	(0)	(2)	(0)	(0)	(0)	-	117
29	Subtransmission	DEM	(6)	(4)	(0)	(2)	(0)	(0)	(0)	-	117
30	Distribution Primary	DEM	(21)	(13)	(1)	(6)	(1)	(0)	(0)	-	105
31	Distribution Secondary	DEM	(9)	(7)	(1)	(2)	-	-	(0)	-	106
32	Distribution	CUST	(9)	(3)	(1)	(0)	(0)	(0)	(0)	(5)	907
33	Other	CUST	(3)	(2)	(0)	(0)	(0)	(0)	(0)	-	412
34	TOTAL OTHER TAXES		(135)	(76)	(7)	(39)	(5)	(3)	(0)	(5)	
35											
36	EQUALS: NON-REVENUE TAXES										
37	Production	DEM	50,567	27,424	2,389	16,517	2,364	1,723	152	-	
38	Production	EGY	5,692	2,872	265	1,977	315	232	30	-	
39	Transmission	DEM	3,530	2,048	169	1,080	135	97	3	-	
40	Subtransmission	DEM	4,064	2,357	194	1,243	155	111	3	-	
41	Distribution Primary	DEM	16,677	10,380	738	4,943	520	0	96	-	
42	Distribution Secondary	DEM	7,263	5,299	427	1,511	-	-	26	-	
43	Distribution	CUST	8,362	3,083	468	225	15	16	4	4,552	
44	Other	CUST	4,306	3,840	372	92	0	0	1	-	
45	TOTAL NON-REVENUE TAXES		100,461	57,303	5,022	27,588	3,503	2,179	314	4,552	

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TAXES OTHER THAN INCOME TAXES - TXOTH

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
46	REGULATORY ASSESSMENT FEE										
47	Production	DEM	629	341	30	206	29	21	2	-	122
48	Production	EGY	47	24	2	16	3	2	0	-	204
49	Transmission	DEM	50	29	2	15	2	1	0	-	117
50	Subtransmission	DEM	54	31	3	16	2	1	0	-	117
51	Distribution Primary	DEM	176	109	8	52	5	0	1	-	105
52	Distribution Secondary	DEM	77	56	5	16	-	-	0	-	106
53	Distribution	CUST	75	28	4	2	0	0	0	41	907
54	Other	CUST	23	21	2	0	0	0	0	-	412
55	TOTAL REGULATORY ASSESSMENT FEE		1,132	639	55	324	42	26	4	41	
56											
57											
58	EQUALS: TAXES OTHER THAN INCOME										
59	Production	DEM	51,197	27,765	2,419	16,722	2,393	1,744	153	-	
60	Production	EGY	5,739	2,896	268	1,994	317	234	30	-	
61	Transmission	DEM	3,580	2,076	171	1,095	137	98	3	-	
62	Subtransmission	DEM	4,118	2,388	197	1,259	157	113	3	-	
63	Distribution Primary	DEM	16,853	10,490	746	4,995	525	0	97	-	
64	Distribution Secondary	DEM	7,340	5,355	431	1,527	-	-	27	-	
65	Distribution	CUST	8,437	3,110	472	227	15	16	4	4,593	
66	Other	CUST	4,329	3,861	374	92	0	0	1	-	
67											
68	TOTAL TAXES OTHER THAN INCOME		101,592	57,942	5,078	27,912	3,545	2,205	317	4,593	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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INCOME TAXES - INCTX

Derivation of Operating Income

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	TOTAL OPERATING REVENUES										
2	Sales Revenue (incl. Transmission Firm Whsl)	REV	1,480,725	920,604	95,215	310,482	44,353	23,795	3,570	82,706	
3	Production	DEM	1,851	1,004	87	605	87	63	6	-	
4	Production	EGY	676	216	33	329	62	33	4	-	
5	Transmission	DEM	932	540	45	285	36	26	1	-	
6	Subtransmission	DEM	256	148	12	78	10	7	0	-	
7	Distribution Primary	DEM	14,946	9,302	662	4,430	466	0	86	-	
8	Distribution Secondary	DEM	349	254	20	73	-	-	1	-	
9	Distribution	CUST	216	80	12	6	0	0	0	118	
10	Other	CUST	18,521	16,523	1,601	392	0	0	5	-	
11	TOTAL OPERATING REVENUES		1,518,472	948,672	97,688	316,679	45,013	23,924	3,673	82,823	
12											
13	LESS: O&M EXPENSE										
14	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-	
15	Production	EGY	41,606	20,996	1,940	14,454	2,301	1,695	220	-	
16	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-	
17	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-	
18	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-	
19	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-	
20	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830	
21	Other	CUST	68,841	59,810	5,825	2,575	180	94	33	324	
22	TOTAL O&M EXPENSE		391,771	241,198	23,375	95,541	12,518	7,830	1,155	10,154	
23											
24	LESS: FUEL & POWER TRANSACTIONS										
25	Production Demand	DEM	-	-	-	-	-	-	-	-	
26	Production Energy	EGY	626	316	29	218	35	26	3	-	
27	TOTAL FUEL & POWER TRANSACTIONS		626	316	29	218	35	26	3	-	
28											
29	LESS: DEPRECIATION EXPENSE										
30	Production	DEM	290,552	157,573	13,726	94,902	13,581	9,899	871	-	
31	Production	EGY	30,632	15,458	1,429	10,642	1,694	1,248	162	-	
32	Transmission	DEM	14,347	8,321	686	4,388	548	393	10	-	
33	Subtransmission	DEM	15,521	9,002	743	4,747	593	425	11	-	
34	Distribution Primary	DEM	76,341	47,516	3,379	22,628	2,380	0	438	-	
35	Distribution Secondary	DEM	43,855	31,998	2,576	9,122	-	-	159	-	
36	Distribution	CUST	47,757	19,058	3,756	2,174	164	179	37	22,390	
37	Other	CUST	12,431	11,087	1,075	265	1	0	3	-	
38	TOTAL DEPRECIATION EXPENSE		531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
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(000's)

INCOME TAXES - INCTX

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
39	LESS: AMORTIZATION EXPENSE										
40	Production	DEM	-	-	-	-	-	-	-	-	
41	Production	EGY	-	-	-	-	-	-	-	-	
42	Transmission	DEM	-	-	-	-	-	-	-	-	
43	Subtransmission	DEM	-	-	-	-	-	-	-	-	
44	Distribution Primary	DEM	-	-	-	-	-	-	-	-	
45	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	
46	Distribution	CUST	-	-	-	-	-	-	-	-	
47	Other	CUST	-	-	-	-	-	-	-	-	
48	TOTAL AMORTIZATION EXPENSE		-	-	-	-	-	-	-	-	
49											
50	LESS: TAXES OTHER THAN INCOME										
51	Production	DEM	51,197	27,765	2,419	16,722	2,393	1,744	153	-	
52	Production	EGY	5,739	2,896	268	1,994	317	234	30	-	
53	Transmission	DEM	3,580	2,076	171	1,095	137	98	3	-	
54	Subtransmission	DEM	4,118	2,388	197	1,259	157	113	3	-	
55	Distribution Primary	DEM	16,853	10,490	746	4,995	525	0	97	-	
56	Distribution Secondary	DEM	7,340	5,355	431	1,527	-	-	27	-	
57	Distribution	CUST	8,437	3,110	472	227	15	16	4	4,593	
58	Other	CUST	4,329	3,861	374	92	0	0	1	-	
59	TOTAL TAXES OTHER THAN INCOME		101,592	57,942	5,078	27,912	3,545	2,205	317	4,593	
60											
61	LESS: LOSS ON DISPOSITION & MISC										
62	Production	DEM	-	-	-	-	-	-	-	-	122
63	Production	EGY	-	-	-	-	-	-	-	-	201
64	Transmission	DEM	-	-	-	-	-	-	-	-	117
65	Subtransmission	DEM	-	-	-	-	-	-	-	-	117
66	Distribution Primary	DEM	-	-	-	-	-	-	-	-	105
67	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
68	Distribution	CUST	-	-	-	-	-	-	-	-	907
69	Other	CUST	-	-	-	-	-	-	-	-	412
70	TOTAL OTHER EXPENSES		-	-	-	-	-	-	-	-	
71											
72	EQUALS: OPERATING INCOME										
73	Sales	REV	1,480,725	920,604	95,215	310,482	44,353	23,795	3,570	82,706	
74	Production	DEM	(499,520)	(270,901)	(23,597)	(163,157)	(23,348)	(17,019)	(1,497)	-	
75	Production	EGY	(77,928)	(39,451)	(3,633)	(26,979)	(4,285)	(3,170)	(411)	-	
76	Transmission	DEM	(20,634)	(11,968)	(987)	(6,311)	(788)	(565)	(15)	-	
77	Subtransmission	DEM	(30,504)	(17,693)	(1,459)	(9,330)	(1,165)	(836)	(22)	-	
78	Distribution Primary	DEM	(137,031)	(85,290)	(6,066)	(40,616)	(4,272)	(0)	(787)	-	
79	Distribution Secondary	DEM	(60,623)	(44,232)	(3,562)	(12,610)	-	-	(219)	-	
80	Distribution	CUST	(94,361)	(43,633)	(8,401)	(4,800)	(359)	(392)	(81)	(36,695)	
81	Other	CUST	(67,080)	(58,234)	(5,673)	(2,540)	(181)	(95)	(33)	(324)	
82	TOTAL OPERATING INCOME		493,046	349,201	41,837	44,140	9,956	1,719	506	45,687	

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INCOME TAXES - INCTX

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
83	LESS: INTEREST EXPENSE										
84	Production	DEM	101,439	55,013	4,792	33,133	4,741	3,456	304	-	122
85	Production	EGY	7,629	3,850	356	2,650	422	311	40	-	201
86	Transmission	DEM	7,483	4,340	358	2,289	286	205	5	-	117
87	Subtransmission	DEM	8,123	4,712	389	2,485	310	223	6	-	117
88	Distribution Primary	DEM	28,304	17,617	1,253	8,389	882	0	162	-	105
89	Distribution Secondary	DEM	12,443	9,079	731	2,588	-	-	45	-	106
90	Distribution	CUST	12,137	4,474	679	327	21	23	5	6,607	907
91	Other	CUST	3,708	3,307	321	79	0	0	1	-	412
92	TOTAL INTEREST EXPENSE		181,266	102,391	8,878	51,940	6,663	4,218	569	6,607	
93											
94	PLUS: PERMANENT TIMING DIFFERENCES										
95	Production	DEM	4,072	2,208	192	1,330	190	139	12	-	122
96	Production	EGY	306	155	14	106	17	12	2	-	201
97	Transmission	DEM	300	174	14	92	11	8	0	-	117
98	Subtransmission	DEM	326	189	16	100	12	9	0	-	117
99	Distribution Primary	DEM	1,136	707	50	337	35	0	7	-	105
100	Distribution Secondary	DEM	499	364	29	104	-	-	2	-	106
101	Distribution	CUST	487	180	27	13	1	1	0	265	907
102	Other	CUST	149	133	13	3	0	0	0	-	412
103	TOTAL PERMANENT TIMING DIFFERENCES		7,276	4,110	356	2,085	267	169	23	265	
104											
105	EQUALS: FLORIDA TAXABLE INCOME										
106	Sales	REV	1,480,725	920,604	95,215	310,482	44,353	23,795	3,570	82,706	
107	Production	DEM	(596,886)	(323,706)	(28,197)	(194,960)	(27,899)	(20,337)	(1,788)	-	
108	Production	EGY	(85,251)	(43,146)	(3,974)	(29,523)	(4,690)	(3,468)	(450)	-	
109	Transmission	DEM	(27,817)	(16,134)	(1,331)	(8,508)	(1,062)	(762)	(20)	-	
110	Subtransmission	DEM	(38,301)	(22,215)	(1,833)	(11,714)	(1,462)	(1,049)	(27)	-	
111	Distribution Primary	DEM	(164,199)	(102,200)	(7,269)	(48,669)	(5,119)	(0)	(943)	-	
112	Distribution Secondary	DEM	(72,566)	(52,946)	(4,263)	(15,094)	-	-	(263)	-	
113	Distribution	CUST	(106,010)	(47,928)	(9,053)	(5,114)	(379)	(414)	(86)	(43,037)	
114	Other	CUST	(70,639)	(61,408)	(5,981)	(2,616)	(181)	(95)	(34)	(324)	
115	TOTAL FLORIDA TAXABLE INCOME		319,056	250,920	33,315	(5,715)	3,560	(2,330)	(40)	39,345	
116											
117	RESULTS: FLORIDA INCOME TAX @ 0.055										
118	Sales	REV	81,440	50,633	5,237	17,077	2,439	1,309	196	4,549	
119	Production	DEM	(32,829)	(17,804)	(1,551)	(10,723)	(1,534)	(1,119)	(98)	-	
120	Production	EGY	(4,689)	(2,373)	(219)	(1,624)	(258)	(191)	(25)	-	
121	Transmission	DEM	(1,530)	(887)	(73)	(468)	(58)	(42)	(1)	-	
122	Subtransmission	DEM	(2,107)	(1,222)	(101)	(644)	(80)	(58)	(1)	-	
123	Distribution Primary	DEM	(9,031)	(5,621)	(400)	(2,677)	(282)	(0)	(52)	-	
124	Distribution Secondary	DEM	(3,991)	(2,912)	(234)	(830)	-	-	(14)	-	
125	Distribution	CUST	(5,831)	(2,636)	(498)	(281)	(21)	(23)	(5)	(2,367)	
126	Other	CUST	(3,885)	(3,377)	(329)	(144)	(10)	(5)	(2)	(18)	
127	TOTAL FLORIDA INCOME TAX		17,548	13,801	1,832	(314)	196	(128)	(2)	2,164	

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INCOME TAXES - INCTX

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
128	EQUALS: FEDERAL TAXABLE INCOME										
129	Sales	REV	1,399,286	869,971	89,978	293,406	41,914	22,487	3,374	78,157	
130	Production	DEM	(564,058)	(305,902)	(26,646)	(184,237)	(26,365)	(19,218)	(1,690)	-	
131	Production	EGY	(80,562)	(40,773)	(3,756)	(27,899)	(4,432)	(3,277)	(425)	-	
132	Transmission	DEM	(26,287)	(15,247)	(1,258)	(8,040)	(1,004)	(720)	(19)	-	
133	Subtransmission	DEM	(36,195)	(20,993)	(1,732)	(11,070)	(1,382)	(992)	(26)	-	
134	Distribution Primary	DEM	(155,168)	(96,579)	(6,869)	(45,992)	(4,837)	(0)	(891)	-	
135	Distribution Secondary	DEM	(68,575)	(50,034)	(4,029)	(14,264)	-	-	(248)	-	
136	Distribution	CUST	(100,180)	(45,292)	(8,555)	(4,832)	(359)	(391)	(81)	(40,670)	
137	Other	CUST	(66,754)	(58,031)	(5,652)	(2,472)	(171)	(90)	(32)	(306)	
138	TOTAL FEDERAL TAXABLE INCOME		301,508	237,119	31,483	(5,400)	3,364	(2,201)	(38)	37,181	
139											
140	RESULTS: FEDERAL INCOME TAX @ 0.21										
141	Sales	REV	293,850	182,694	18,895	61,615	8,802	4,722	709	16,413	
142	Production	DEM	(118,452)	(64,239)	(5,596)	(38,690)	(5,537)	(4,036)	(355)	-	
143	Production	EGY	(16,918)	(8,562)	(789)	(5,859)	(931)	(688)	(89)	-	
144	Transmission	DEM	(5,520)	(3,202)	(264)	(1,688)	(211)	(151)	(4)	-	
145	Subtransmission	DEM	(7,601)	(4,409)	(364)	(2,325)	(290)	(208)	(5)	-	
146	Distribution Primary	DEM	(32,585)	(20,282)	(1,442)	(9,658)	(1,016)	(0)	(187)	-	
147	Distribution Secondary	DEM	(14,401)	(10,507)	(846)	(2,995)	-	-	(52)	-	
148	Distribution	CUST	(21,038)	(9,511)	(1,797)	(1,015)	(75)	(82)	(17)	(8,541)	
149	Other	CUST	(14,018)	(12,186)	(1,187)	(519)	(36)	(19)	(7)	(64)	
150	TOTAL FEDERAL INCOME TAX		63,317	49,795	6,611	(1,134)	707	(462)	(8)	7,808	
151											
152	ADJ. TO INCOME TAXES (True-ups, Excess Deferred, ITC AND PDA)										
153	Production	DEM	(68,583)	(37,194)	(3,240)	(22,401)	(3,206)	(2,337)	(205)	-	122
154	Production	EGY	(4,743)	(2,394)	(221)	(1,648)	(262)	(193)	(25)	-	201
155	Transmission	DEM	(1,517)	(880)	(73)	(464)	(58)	(42)	(1)	-	117
156	Subtransmission	DEM	(1,134)	(658)	(54)	(347)	(43)	(31)	(1)	-	117
157	Distribution Primary	DEM	(4,002)	(2,491)	(177)	(1,186)	(125)	(0)	(23)	-	105
158	Distribution Secondary	DEM	(1,260)	(920)	(74)	(262)	-	-	(5)	-	106
159	Distribution	CUST	(7,111)	(2,622)	(398)	(192)	(12)	(13)	(3)	(3,871)	907
160	Other	CUST	(842)	(751)	(73)	(18)	(0)	(0)	(0)	-	412
161	TOTAL ADJUSTMENT TO INCOME TAXES		(89,192)	(47,908)	(4,309)	(26,518)	(3,706)	(2,616)	(263)	(3,871)	
162											
163	TOTAL INCOME TAXES (FED, STATE, AND ADJUSTMENTS)										
164	Sales	REV	375,290	233,327	24,132	78,692	11,241	6,031	905	20,962	
165	Production	DEM	(219,864)	(119,237)	(10,386)	(71,814)	(10,277)	(7,491)	(659)	-	
166	Production	EGY	(26,350)	(13,329)	(1,228)	(9,130)	(1,451)	(1,072)	(139)	-	
167	Transmission	DEM	(8,567)	(4,969)	(410)	(2,620)	(327)	(235)	(6)	-	
168	Subtransmission	DEM	(10,842)	(6,288)	(519)	(3,316)	(414)	(297)	(8)	-	
169	Distribution Primary	DEM	(45,618)	(28,393)	(2,019)	(13,521)	(1,422)	(0)	(262)	-	
170	Distribution Secondary	DEM	(19,652)	(14,339)	(1,155)	(4,088)	-	-	(71)	-	
171	Distribution	CUST	(33,979)	(14,769)	(2,692)	(1,488)	(109)	(118)	(25)	(14,779)	
172	Other	CUST	(18,745)	(16,314)	(1,589)	(681)	(46)	(24)	(9)	(82)	
173											
174	TOTAL INCOME TAXES		(8,327)	15,688	4,134	(27,966)	(2,804)	(3,207)	(273)	6,101	

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PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION PLANT										
2	Production Demand	DEM	4,493,529	2,436,947	212,273	1,467,714	210,034	153,099	13,463	-	122
3	Production Demand - Solar Facilities	DEM	2,068,978	1,122,056	97,738	675,787	96,707	70,492	6,199	-	121
4	Production Energy	EGY	570,340	287,813	26,597	198,139	31,541	23,236	3,013	-	201
5	TOTAL PRODUCTION PLANT		7,132,848	3,846,816	336,608	2,341,640	338,281	246,828	22,675	-	
6											
7											
8	TRANSMISSION PLANT										
9	Step-Up Substations	DEM	191,967	104,108	9,068	62,702	8,973	6,541	575	-	122
10	Step-Up Substations - Solar	DEM	-	-	-	-	-	-	-	-	121
11	Step-Up Substations		191,967	104,108	9,068	62,702	8,973	6,541	575	-	
12											
13	High-Volt Substations & LINES	DEM	499,579	289,762	23,902	152,796	19,075	13,689	354	-	117
14											
15	Subtransmission										
16	Substations	DEM	225,310	130,683	10,780	68,911	8,603	6,174	160	-	117
17	LINES	DEM	265,675	154,095	12,711	81,257	10,144	7,280	188	-	117
18	Subtransmission		490,985	284,778	23,491	150,168	18,746	13,453	348	-	
19											
20	TOTAL TRANSMISSION PLANT		1,182,531	678,648	56,462	365,666	46,794	33,683	1,277	-	

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PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
21	DISTRIBUTION PLANT										
22	Substations	DEM	368,438	229,322	16,310	109,205	11,486	0	2,115	-	105
23											
24	Poles Direct	CUST	32,074	-	-	-	-	-	-	32,074	310
25	Poles Primary	DEM	300,991	187,342	13,324	89,214	9,384	0	1,728	-	105
26	Poles Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
27	Poles Secondary	DEM	90,396	65,956	5,311	18,802	-	-	327	-	106
28	Poles Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
29	TOTAL POLES		423,461	253,297	18,635	108,016	9,384	0	2,055	32,074	
30											
31	OH LINES Direct	CUST	4,543	-	-	-	-	-	-	4,543	310
32	OH LINES Primary	DEM	251,747	156,691	11,144	74,618	7,848	0	1,445	-	105
33	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
34	OH LINES Secondary	DEM	38,298	27,943	2,250	7,966	-	-	139	-	106
35	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
36	TOTAL OH LINES		294,587	184,635	13,394	82,584	7,848	0	1,584	4,543	
37											
38	UG LINES Direct	CUST	386	-	-	-	-	-	-	386	310
39	UG LINES Primary	DEM	753,247	468,833	33,345	223,263	23,483	0	4,324	-	105
40	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
41	UG LINES Secondary	DEM	57,432	41,904	3,374	11,946	-	-	208	-	106
42	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
43	TOTAL UG LINES		811,065	510,737	36,719	235,209	23,483	0	4,532	386	
44											
45	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
46	Transformers Primary	DEM	164,150	102,170	7,267	48,654	5,117	0	942	-	105
47	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
48	Transformers Secondary	DEM	833,929	608,463	48,993	173,457	-	-	3,017	-	106
49	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
50	TOTAL Transformers		998,080	710,632	56,260	222,111	5,117	0	3,959	-	
51											
52	Services	CUST	228,413	203,776	19,749	4,830	-	-	58	-	420
53	Meters	CUST	149,852	102,300	26,678	17,553	1,443	1,574	304	-	308
54	Installations on Customers' Premises	CUST	-	0	-	-	-	-	-	-	309
55	Street Lighting	CUST	414,979	-	-	-	-	-	-	414,979	310
56											
57	Distribution Plant	DEM	2,858,628	1,888,624	141,318	757,125	57,318	0	14,244	-	
58	Distribution Plant	CUST	830,247	306,076	46,428	22,383	1,443	1,574	361	451,982	
59											
60	TOTAL DISTRIBUTION PLANT		3,688,875	2,194,700	187,745	779,508	58,761	1,574	14,605	451,982	
61											
62											
63	PROD, TRANS, & DIST PLANT										
64	Production	DEM	6,754,475	3,663,111	319,079	2,206,202	315,714	230,132	20,237	-	
65	Production	EGY	570,340	287,813	26,597	198,139	31,541	23,236	3,013	-	
66	Transmission	DEM	499,579	289,762	23,902	152,796	19,075	13,689	354	-	
67	Subtransmission	DEM	490,985	284,778	23,491	150,168	18,746	13,453	348	-	
68	Distribution Primary	DEM	1,838,573	1,144,357	81,390	544,954	57,318	0	10,554	-	

PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
69	Distribution Secondary	DEM	1,020,055	744,266	59,928	212,171	-	-	3,690	-	
70	Distribution	CUST	830,247	306,076	46,428	22,383	1,443	1,574	361	451,982	
71	Other	CUST	-	-	-	-	-	-	-	-	
72	TOTAL PROD, TRANS, & DIST PLANT		12,004,254	6,720,164	580,816	3,486,814	443,837	282,085	38,557	451,982	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
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TAMPA ELECTRIC COMPANY
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(000's)

PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
73	PLUS: COMMUNICATION EQUIPMENT										
74	Production	DEM	30,060	16,302	1,420	9,818	1,405	1,024	90	-	122
75	Production	EGY	7,469	3,769	348	2,595	413	304	39	-	201
76	Transmission	DEM	5,299	3,073	254	1,621	202	145	4	-	117
77	Subtransmission	DEM	4,265	2,474	204	1,305	163	117	3	-	117
78	Distribution Primary	DEM	27,531	17,136	1,219	8,160	858	0	158	-	105
79	Distribution Secondary	DEM	8,947	6,528	526	1,861	-	-	32	-	106
80	Distribution	CUST	10,610	3,911	593	286	18	20	5	5,776	907
81	Other	CUST	14,371	12,818	1,243	306	1	0	4	-	412
82	TOTAL COMMUNICATION EQUIPMENT		108,551	66,011	5,806	25,951	3,061	1,611	335	5,776	
83											
84	PLUS: TRANSPORTATION EQUIPMENT										
85	Production	DEM	7,483	4,058	353	2,444	350	255	22	-	122
86	Production	EGY	-	-	-	-	-	-	-	-	201
87	Transmission	DEM	2,560	1,485	122	783	98	70	2	-	117
88	Subtransmission	DEM	7,197	4,174	344	2,201	275	197	5	-	117
89	Distribution Primary	DEM	37,791	23,522	1,673	11,201	1,178	0	217	-	105
90	Distribution Secondary	DEM	6,519	4,757	383	1,356	-	-	24	-	106
91	Distribution	CUST	24,225	8,931	1,355	653	42	46	11	13,188	907
92	Other	CUST	32,813	29,265	2,837	699	2	0	9	-	412
93	TOTAL TRANSPORTATION EQUIPMENT		118,587	76,191	7,068	19,337	1,945	569	289	13,188	
94											
95	PLUS: GENERAL & INTANGIBLE										
96	Production	DEM	402,516	218,294	19,015	131,473	18,814	13,714	1,206	-	122
97	Production - Solar	DEM	4,620	2,506	218	1,509	216	157	14	-	121
98	Production	EGY	102,740	51,846	4,791	35,692	5,682	4,186	543	-	201
99	Transmission	DEM	15,422	8,945	738	4,717	589	423	11	-	117
100	Subtransmission	DEM	43,359	25,149	2,075	13,261	1,655	1,188	31	-	117
101	Distribution Primary	DEM	234,845	146,171	10,396	69,608	7,321	0	1,348	-	105
102	Distribution Secondary	DEM	39,277	28,658	2,308	8,170	-	-	142	-	106
103	Distribution	CUST	145,948	53,805	8,161	3,935	254	277	64	79,453	907
104	Other	CUST	197,960	176,558	17,116	4,215	14	3	54	-	412
105	TOTAL GENERAL & INTANGIBLE		1,186,687	711,931	64,817	272,580	34,545	19,947	3,412	79,453	
106											
107	PLUS: ROU LEASES										
108	Production	DEM	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	122
109											
110	EQUALS: PLANT IN SERVICE										
111	Production	DEM	7,199,154	3,904,271	340,086	2,351,447	336,499	245,283	21,569	-	
112	Production	EGY	680,548	343,428	31,737	236,427	37,635	27,726	3,595	-	
113	Transmission	DEM	522,859	303,265	25,016	159,917	19,963	14,327	371	-	
114	Subtransmission	DEM	545,806	316,575	26,114	166,935	20,840	14,956	387	-	
115	Distribution Primary	DEM	2,138,740	1,331,186	94,677	633,924	66,676	0	12,277	-	
116	Distribution Secondary	DEM	1,074,798	784,208	63,144	223,557	-	-	3,888	-	
117	Distribution	CUST	1,011,030	372,723	56,537	27,257	1,757	1,917	440	550,399	
118	Other	CUST	245,144	218,641	21,195	5,220	18	3	67	-	
119											
120	TOTAL PLANT IN SERVICE		13,418,078	7,574,297	658,507	3,804,683	483,388	304,212	42,594	550,399	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
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TAMPA ELECTRIC COMPANY
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(000's)

PLANT HELD FOR FUTURE USE - PHFFU

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PLANT HELD FOR FUTURE USE										
2	Production	DEM	26,353	14,292	1,245	8,608	1,232	898	79	-	122
3	Production - Solar	DEM	-	-	-	-	-	-	-	-	121
4	Production	EGY	-	-	-	-	-	-	-	-	201
5	Transmission	DEM	10,636	6,169	509	3,253	406	291	8	-	117
6	Subtransmission	DEM	10,453	6,063	500	3,197	399	286	7	-	117
7	Distribution Primary	DEM	20,590	12,816	911	6,103	642	0	118	-	105
8	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
9	Distribution	CUST	-	-	-	-	-	-	-	-	907
10	Other	CUST	-	-	-	-	-	-	-	-	412
11											
12	TOTAL PLANT HELD FOR FUTURE USE		68,034	39,340	3,165	21,161	2,679	1,476	212	-	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION RESERVE										
2	Production Demand	DEM	1,542,785	836,689	72,881	503,917	72,112	52,564	4,622	-	122
3	Production Demand - Solar Facilities	DEM	222,986	120,930	10,534	72,833	10,423	7,597	668	-	121
4	Production Energy	EGY	293,748	148,235	13,699	102,050	16,245	11,968	1,552	-	201
5	TOTAL PRODUCTION DEPRE RESERVE		2,059,519	1,105,854	97,113	678,800	98,779	72,129	6,842	-	
6											
7											
8	TRANSMISSION RESERVE										
9	Step-Up Substations	DEM	46,016	24,955	2,174	15,030	2,151	1,568	138	-	122
10	Step-Up Substations - Solar	DEM	-	-	-	-	-	-	-	-	121
11	Step-Up Substations		46,016	24,955	2,174	15,030	2,151	1,568	138	-	
12											
13	High-Volt Transmission LINES	DEM	132,871	77,067	6,357	40,639	5,073	3,641	94	-	117
14											
15	Subtransmission										
16	Substations	DEM	43,645	25,314	2,088	13,349	1,666	1,196	31	-	117
17	LINES	DEM	72,368	41,975	3,462	22,134	2,763	1,983	51	-	117
18	Subtransmission		116,013	67,289	5,551	35,483	4,430	3,179	82	-	
19											
20	TOTAL TRANSMISSION DEPRE RESERVE		294,899	169,311	14,082	91,151	11,654	8,387	314	-	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
21	DISTRIBUTION RESERVE										
22	Substations	DEM	92,546	57,602	4,097	27,431	2,885	0	531	-	105
23											
24	Poles Direct	CUST	14,632	-	-	-	-	-	-	14,632	310
25	Poles Primary	DEM	137,306	85,461	6,078	40,697	4,281	0	788	-	105
26	Poles Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
27	Poles Secondary	DEM	41,237	30,088	2,423	8,577	-	-	149	-	106
28	Poles Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
29	TOTAL POLES		193,174	115,549	8,501	49,275	4,281	0	937	14,632	
30											
31	OH LINES Direct	CUST	2,332	-	-	-	-	-	-	2,332	310
32	OH LINES Primary	DEM	129,230	80,435	5,721	38,304	4,029	0	742	-	105
33	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
34	OH LINES Secondary	DEM	19,659	14,344	1,155	4,089	-	-	71	-	106
35	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
36	TOTAL OH LINES		151,221	94,779	6,876	42,393	4,029	0	813	2,332	
37											
38	UG LINES Direct	CUST	72	-	-	-	-	-	-	72	310
39	UG LINES Primary	DEM	141,098	87,822	6,246	41,822	4,399	0	810	-	105
40	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
41	UG LINES Secondary	DEM	10,758	7,850	632	2,238	-	-	39	-	106
42	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
43	TOTAL UG LINES		151,929	95,671	6,878	44,059	4,399	0	849	72	
44											
45	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
46	Transformers Primary	DEM	61,807	38,470	2,736	18,320	1,927	0	355	-	105
47	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
48	Transformers Secondary	DEM	313,999	229,104	18,447	65,311	-	-	1,136	-	106
49	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
50	TOTAL Transformers		375,806	267,574	21,183	83,631	1,927	0	1,491	-	
51											
52	Services	CUST	143,574	128,088	12,414	3,036	-	-	36	-	420
53	Meters	CUST	25,381	17,327	4,519	2,973	244	267	51	-	308
54	Installations on Customers' Premises	CUST	-	-	-	-	-	-	-	-	309
55	Street Lighting	CUST	132,134	-	-	-	-	-	-	132,134	310
56											
57	Distribution Reserve	DEM	947,639	631,175	47,535	246,789	17,520	0	4,621	-	
58	Distribution Reserve	CUST	318,125	145,415	16,932	6,009	244	267	88	149,170	
59											
60	TOTAL DISTRIBUTION DEPRE RESERVE		1,265,764	776,589	64,467	252,798	17,765	267	4,709	149,170	
61											
62											

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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(000's)

ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
63	PROD, TRANS, & DIST RESERVE										
64	Production	DEM	1,811,786	982,574	85,588	591,780	84,685	61,729	5,428	-	
65	Production	EGY	293,748	148,235	13,699	102,050	16,245	11,968	1,552	-	
66	Transmission	DEM	132,871	77,067	6,357	40,639	5,073	3,641	94	-	
67	Subtransmission	DEM	116,013	67,289	5,551	35,483	4,430	3,179	82	-	
68	Distribution Primary	DEM	561,987	349,790	24,878	166,573	17,520	0	3,226	-	
69	Distribution Secondary	DEM	385,653	281,385	22,657	80,216	-	-	1,395	-	
70	Distribution	CUST	318,125	145,415	16,932	6,009	244	267	88	149,170	
71	Other	CUST	-	-	-	-	-	-	-	-	
72											
73	TOTAL PROD, TRANS, & DIST DEPRE RESERVE		3,620,182	2,051,755	175,662	1,022,749	128,197	80,783	11,865	149,170	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
74	PLUS: COMMUNICATION EQUIPMENT										
75	Production	DEM	13,816	7,493	653	4,513	646	471	41	-	122
76	Production	EGY	3,433	1,732	160	1,193	190	140	18	-	201
77	Transmission	DEM	2,435	1,412	117	745	93	67	2	-	117
78	Subtransmission	DEM	1,960	1,137	94	600	75	54	1	-	117
79	Distribution Primary	DEM	12,653	7,876	560	3,750	394	0	73	-	105
80	Distribution Secondary	DEM	4,112	3,000	242	855	-	-	15	-	106
81	Distribution	CUST	4,876	1,798	273	131	8	9	2	2,655	907
82	Other	CUST	6,605	5,891	571	141	0	0	2	-	412
83	TOTAL COMM EQUIP DEPRE RESERVE		49,891	30,339	2,669	11,927	1,407	740	154	2,655	
84											
85	PLUS: TRANSPORTATION EQUIPMENT										
86	Production	DEM	2,681	1,454	127	876	125	91	8	-	122
87	Production	EGY	-	-	-	-	-	-	-	-	201
88	Transmission	DEM	891	517	43	273	34	24	1	-	117
89	Subtransmission	DEM	2,505	1,453	120	766	96	69	2	-	117
90	Distribution Primary	DEM	13,156	8,189	582	3,900	410	0	76	-	105
91	Distribution Secondary	DEM	2,270	1,656	133	472	-	-	8	-	106
92	Distribution	CUST	8,433	3,109	472	227	15	16	4	4,591	907
93	Other	CUST	11,423	10,188	988	243	1	0	3	-	412
94	TOTAL TRANSP EQUIP DEPRE RESERVE		41,360	26,566	2,464	6,757	681	201	101	4,591	
95											
96	PLUS: GENERAL & INTANGIBLE										
97	Production	DEM	99,691	54,065	4,709	32,562	4,660	3,397	299	-	122
98	Production - Solar	DEM	439	238	21	143	21	15	1	-	121
99	Production	EGY	25,439	12,837	1,186	8,838	1,407	1,036	134	-	201
100	Transmission	DEM	3,818	2,215	183	1,168	146	105	3	-	117
101	Subtransmission	DEM	10,736	6,227	514	3,284	410	294	8	-	117
102	Distribution Primary	DEM	58,293	36,282	2,580	17,278	1,817	0	335	-	105
103	Distribution Secondary	DEM	9,725	7,096	571	2,023	-	-	35	-	106
104	Distribution	CUST	36,137	13,322	2,021	974	63	69	16	19,673	907
105	Other	CUST	49,095	43,788	4,245	1,045	4	1	13	-	412
106	TOTAL GENERAL & INTANGIBLE		293,374	176,070	16,030	67,315	8,526	4,916	844	19,673	
107											
108	EQUALS: DEPRECIATION RESERVE										
109	Production	DEM	1,928,413	1,045,824	91,098	629,874	90,137	65,703	5,778	-	
110	Production	EGY	322,620	162,805	15,045	112,080	17,841	13,144	1,704	-	
111	Transmission	DEM	140,015	81,211	6,699	42,824	5,346	3,837	99	-	
112	Subtransmission	DEM	131,215	76,106	6,278	40,132	5,010	3,595	93	-	
113	Distribution Primary	DEM	646,089	402,136	28,601	191,501	20,142	0	3,709	-	
114	Distribution Secondary	DEM	401,759	293,137	23,603	83,566	-	-	1,453	-	
115	Distribution	CUST	367,572	163,644	19,697	7,342	330	360	109	176,089	
116	Other	CUST	67,124	59,867	5,804	1,429	5	1	18	-	
117											
118	TOTAL ACCUM DEPRECIATION RESERVE		4,004,807	2,284,730	196,825	1,108,748	138,811	86,640	12,964	176,089	

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TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

WORKING CAPITAL - WKCAP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	MATERIALS & SUPPLIES										
2	Production	DEM	91,095	49,403	4,303	29,754	4,258	3,104	273	-	122
3	Production	EGY	7,692	3,882	359	2,672	425	313	41	-	201
4	Transmission	DEM	6,738	3,908	322	2,061	257	185	5	-	117
5	Subtransmission	DEM	6,622	3,841	317	2,025	253	181	5	-	117
6	Distribution Primary	DEM	24,796	15,434	1,098	7,350	773	0	142	-	105
7	Distribution Secondary	DEM	13,757	10,038	808	2,861	-	-	50	-	106
8	Distribution	CUST	11,197	4,128	626	302	19	21	5	6,096	907
9	Other	CUST	-	-	-	-	-	-	-	-	412
10	TOTAL MATERIALS & SUPPLIES		161,897	90,632	7,833	47,025	5,986	3,804	520	6,096	
11											
12	PLUS: EXCLUSIONS										
13	Production	DEM	(276,878)	(150,157)	(13,080)	(90,436)	(12,942)	(9,434)	(830)	-	122
14	Production	EGY	(26,078)	(13,160)	(1,216)	(9,060)	(1,442)	(1,062)	(138)	-	201
15	Transmission	DEM	(20,443)	(11,857)	(978)	(6,253)	(781)	(560)	(14)	-	117
16	Subtransmission	DEM	(21,316)	(12,363)	(1,020)	(6,519)	(814)	(584)	(15)	-	117
17	Distribution Primary	DEM	(82,744)	(51,501)	(3,663)	(24,525)	(2,580)	(0)	(475)	-	105
18	Distribution Secondary	DEM	(41,186)	(30,050)	(2,420)	(8,567)	-	-	(149)	-	106
19	Distribution	CUST	(38,742)	(14,283)	(2,166)	(1,044)	(67)	(73)	(17)	(21,091)	907
20	Other	CUST	(9,394)	(8,378)	(812)	(200)	(1)	(0)	(3)	-	412
21	TOTAL CASH		(516,781)	(291,751)	(25,355)	(146,604)	(18,626)	(11,714)	(1,640)	(21,091)	
22											
23	PLUS: NET ADDITIONS										
24	Production	DEM	600,864	325,863	28,385	196,259	28,085	20,472	1,800	-	122
25	Production	EGY	56,593	28,559	2,639	19,661	3,130	2,306	299	-	201
26	Transmission	DEM	44,365	25,732	2,123	13,569	1,694	1,216	31	-	117
27	Subtransmission	DEM	46,258	26,830	2,213	14,148	1,766	1,268	33	-	117
28	Distribution Primary	DEM	179,567	111,765	7,949	53,224	5,598	0	1,031	-	105
29	Distribution Secondary	DEM	89,379	65,214	5,251	18,591	-	-	323	-	106
30	Distribution	CUST	84,076	30,995	4,702	2,267	146	159	37	45,770	907
31	Other	CUST	20,386	18,182	1,763	434	1	0	6	-	412
32	TOTAL NET ADDITIONS		1,121,487	633,140	55,024	318,152	40,421	25,421	3,560	45,770	
33											
34	MINUS: NET DEDUCTIONS										
35	Production	DEM	383,918	208,208	18,136	125,398	17,945	13,080	1,150	-	122
36	Production	EGY	36,160	18,248	1,686	12,562	2,000	1,473	191	-	201
37	Transmission	DEM	28,347	16,441	1,356	8,670	1,082	777	20	-	117
38	Subtransmission	DEM	29,556	17,143	1,414	9,040	1,128	810	21	-	117
39	Distribution Primary	DEM	114,733	71,412	5,079	34,007	3,577	0	659	-	105
40	Distribution Secondary	DEM	57,108	41,668	3,355	11,878	-	-	207	-	106
41	Distribution	CUST	53,720	19,804	3,004	1,448	93	102	23	29,245	907
42	Other	CUST	13,025	11,617	1,126	277	1	0	4	-	412
43	TOTAL NET DEDUCTIONS		716,567	404,541	35,157	203,281	25,827	16,242	2,274	29,245	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

WORKING CAPITAL - WKCAP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
44	PLUS: FUEL INVENTORY										
45	Production	EGY	36,635	18,487	1,708	12,727	2,026	1,493	194	-	201
46	TOTAL FUEL INVENTORY		36,635	18,487	1,708	12,727	2,026	1,493	194	-	
47											
48	EQUALS: WORKING CAPITAL, (Incl. fuel inventory)										
49	Production	DEM	31,163	16,900	1,472	10,179	1,457	1,062	93	-	
50	Production	EGY	38,682	19,520	1,804	13,438	2,139	1,576	204	-	
51	Transmission	DEM	2,313	1,341	111	707	88	63	2	-	
52	Subtransmission	DEM	2,008	1,165	96	614	77	55	1	-	
53	Distribution Primary	DEM	6,885	4,286	305	2,041	215	0	40	-	
54	Distribution Secondary	DEM	4,842	3,533	284	1,007	-	-	18	-	
55	Distribution	CUST	2,811	1,036	157	76	5	5	1	1,530	
56	Other	CUST	(2,033)	(1,814)	(176)	(43)	(0)	(0)	(1)	-	
57											
58	TOTAL WORKING CAPITAL		86,671	45,968	4,053	28,019	3,980	2,761	358	1,530	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

CONSTRUCTION WORK IN PROGRESS - CWIP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION CWIP										
2	Production Demand	DEM	106,808	57,924	5,046	34,886	4,992	3,639	320	-	122
3	Production Demand - Solar	DEM	-	-	-	-	-	-	-	-	121
4	Production Energy	EGY	3,054	1,541	142	1,061	169	124	16	-	201
5	TOTAL PRODUCTION CWIP		109,862	59,466	5,188	35,948	5,161	3,763	336	-	
6											
7											
8	TRANSMISSION CWIP										
9	Step-Up Substations	DEM	-	-	-	-	-	-	-	-	122
10	Hi-Volt Transmission	DEM	6,812	3,951	326	2,083	260	187	5	-	117
11	Subtransmission Common	DEM	6,695	3,883	320	2,048	256	183	5	-	117
12	TOTAL TRANSMISSION CWIP		13,507	7,834	646	4,131	516	370	10	-	
13											
14											
15	DISTRIBUTION CWIP										
16	Distribution Primary	DEM	(18,323)	(11,405)	(811)	(5,431)	(571)	(0)	(105)	-	105
17	Distribution Secondary	DEM	(10,166)	(7,417)	(597)	(2,115)	-	-	(37)	-	106
18	Distribution	CUST	(8,274)	(3,050)	(463)	(223)	(14)	(16)	(4)	(4,504)	907
19	TOTAL DISTRIBUTION CWIP		(36,764)	(21,873)	(1,871)	(7,769)	(586)	(16)	(146)	(4,504)	
20											
21											
22	PROD, TRANS & DIST CWIP										
23	Production	DEM	106,808	57,924	5,046	34,886	4,992	3,639	320	-	
24	Production	EGY	3,054	1,541	142	1,061	169	124	16	-	
25	Transmission	DEM	6,812	3,951	326	2,083	260	187	5	-	
26	Subtransmission	DEM	6,695	3,883	320	2,048	256	183	5	-	
27	Distribution Primary	DEM	(18,323)	(11,405)	(811)	(5,431)	(571)	(0)	(105)	-	
28	Distribution Secondary	DEM	(10,166)	(7,417)	(597)	(2,115)	-	-	(37)	-	
29	Distribution	CUST	(8,274)	(3,050)	(463)	(223)	(14)	(16)	(4)	(4,504)	
30	Other	CUST	-	-	-	-	-	-	-	-	
31	TOTAL PROD, TRANS & DIST CWIP		86,605	45,427	3,963	32,310	5,091	4,118	200	(4,504)	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

CONSTRUCTION WORK IN PROGRESS - CWIP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
32	PLUS: GENERAL CWIP										
33	Production	DEM	48,112	26,092	2,273	15,715	2,249	1,639	144	-	122
34	Production	EGY	12,702	6,410	592	4,413	702	517	67	-	201
35	Transmission	DEM	1,907	1,106	91	583	73	52	1	-	117
36	Subtransmission	DEM	5,360	3,109	256	1,640	205	147	4	-	117
37	Distribution Primary	DEM	28,149	17,520	1,246	8,343	878	0	162	-	105
38	Distribution Secondary	DEM	4,856	3,543	285	1,010	-	-	18	-	106
39	Distribution	CUST	18,044	6,652	1,009	486	31	34	8	9,823	907
40	Other	CUST	24,441	21,798	2,113	520	2	0	7	-	412
41	TOTAL GENERAL CWIP		143,570	86,230	7,866	32,710	4,139	2,390	410	9,823	
42											
43	EQUALS: TOTAL CWIP										
44	Production	DEM	154,919	84,016	7,318	50,601	7,241	5,278	464	-	
45	Production	EGY	15,756	7,951	735	5,474	871	642	83	-	
46	Transmission	DEM	8,719	5,057	417	2,667	333	239	6	-	
47	Subtransmission	DEM	12,055	6,992	577	3,687	460	330	9	-	
48	Distribution Primary	DEM	9,825	6,115	435	2,912	306	0	56	-	
49	Distribution Secondary	DEM	(5,310)	(3,874)	(312)	(1,104)	-	-	(19)	-	
50	Distribution	CUST	9,769	3,602	546	263	17	19	4	5,318	
51	Other	CUST	24,441	21,798	2,113	520	2	0	7	-	
52											
53	TOTAL CWIP		230,175	131,658	11,829	65,020	9,231	6,508	610	5,318	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

NET PLANT AND RATE BASE - RBASE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PLANT IN SERVICE										
2	Production	DEM	7,199,154	3,904,271	340,086	2,351,447	336,499	245,283	21,569	-	
3	Production	EGY	680,548	343,428	31,737	236,427	37,635	27,726	3,595	-	
4	Transmission	DEM	522,859	303,265	25,016	159,917	19,963	14,327	371	-	
5	Subtransmission	DEM	545,806	316,575	26,114	166,935	20,840	14,956	387	-	
6	Distribution Primary	DEM	2,138,740	1,331,186	94,677	633,924	66,676	0	12,277	-	
7	Distribution Secondary	DEM	1,074,798	784,208	63,144	223,557	-	-	3,888	-	
8	Distribution	CUST	1,011,030	372,723	56,537	27,257	1,757	1,917	440	550,399	
9	Other	CUST	245,144	218,641	21,195	5,220	18	3	67	-	
10	TOTAL PLANT IN SERVICE		13,418,078	7,574,297	658,507	3,804,683	483,388	304,212	42,594	550,399	
11											
12	PLUS: PLANT HELD FOR FUTURE USE										
13	Production	DEM	26,353	14,292	1,245	8,608	1,232	898	79	-	
14	Production	EGY	-	-	-	-	-	-	-	-	
15	Transmission	DEM	10,636	6,169	509	3,253	406	291	8	-	
16	Subtransmission	DEM	10,453	6,063	500	3,197	399	286	7	-	
17	Distribution Primary	DEM	20,590	12,816	911	6,103	642	0	118	-	
18	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	
19	Distribution	CUST	-	-	-	-	-	-	-	-	
20	Other	CUST	-	-	-	-	-	-	-	-	
21	TOTAL PLANT HELD FOR FUTURE USE		68,034	39,340	3,165	21,161	2,679	1,476	212	-	
22											
23	EQUALS: TOTAL PLANT										
24	Production	DEM	7,225,507	3,918,563	341,331	2,360,055	337,730	246,181	21,648	-	
25	Production	EGY	680,548	343,428	31,737	236,427	37,635	27,726	3,595	-	
26	Transmission	DEM	533,495	309,434	25,525	163,170	20,370	14,618	378	-	
27	Subtransmission	DEM	556,259	322,638	26,614	170,132	21,239	15,242	394	-	
28	Distribution Primary	DEM	2,159,331	1,344,002	95,589	640,027	67,318	0	12,395	-	
29	Distribution Secondary	DEM	1,074,798	784,208	63,144	223,557	-	-	3,888	-	
30	Distribution	CUST	1,011,030	372,723	56,537	27,257	1,757	1,917	440	550,399	
31	Other	CUST	245,144	218,641	21,195	5,220	18	3	67	-	
32	TOTAL PLANT		13,486,112	7,613,637	661,672	3,825,844	486,067	305,687	42,806	550,399	
33											
34	LESS: DEPRECIATION RESERVE										
35	Production	DEM	1,928,413	1,045,824	91,098	629,874	90,137	65,703	5,778	-	
36	Production	EGY	322,620	162,805	15,045	112,080	17,841	13,144	1,704	-	
37	Transmission	DEM	140,015	81,211	6,699	42,824	5,346	3,837	99	-	
38	Subtransmission	DEM	131,215	76,106	6,278	40,132	5,010	3,595	93	-	
39	Distribution Primary	DEM	646,089	402,136	28,601	191,501	20,142	0	3,709	-	
40	Distribution Secondary	DEM	401,759	293,137	23,603	83,566	-	-	1,453	-	
41	Distribution	CUST	367,572	163,644	19,697	7,342	330	360	109	176,089	
42	Other	CUST	67,124	59,867	5,804	1,429	5	1	18	-	
43	TOTAL DEPRECIATION RESERVE		4,004,807	2,284,730	196,825	1,108,748	138,811	86,640	12,964	176,089	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

NET PLANT AND RATE BASE - RBASE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
44	EQUALS: NET PLANT										
45	Production	DEM	5,297,094	2,872,739	250,233	1,730,181	247,594	180,478	15,870	-	
46	Production	EGY	357,929	180,623	16,692	124,347	19,794	14,582	1,891	-	
47	Transmission	DEM	393,480	228,223	18,826	120,346	15,024	10,782	279	-	
48	Subtransmission	DEM	425,045	246,532	20,336	130,000	16,229	11,647	301	-	
49	Distribution Primary	DEM	1,513,241	941,866	66,988	448,525	47,176	0	8,687	-	
50	Distribution Secondary	DEM	673,039	491,071	39,541	139,992	-	-	2,435	-	
51	Distribution	CUST	643,458	209,079	36,840	19,915	1,427	1,557	331	374,310	
52	Other	CUST	178,020	158,774	15,392	3,791	13	2	49	-	
53	TOTAL NET PLANT		9,481,305	5,328,907	464,847	2,717,096	347,255	219,047	29,842	374,310	
54											
55	PLUS: WORKING CAPITAL										
56	Production	DEM	31,163	16,900	1,472	10,179	1,457	1,062	93	-	
57	Production	EGY	38,682	19,520	1,804	13,438	2,139	1,576	204	-	
58	Transmission	DEM	2,313	1,341	111	707	88	63	2	-	
59	Subtransmission	DEM	2,008	1,165	96	614	77	55	1	-	
60	Distribution Primary	DEM	6,885	4,286	305	2,041	215	0	40	-	
61	Distribution Secondary	DEM	4,842	3,533	284	1,007	-	-	18	-	
62	Distribution	CUST	2,811	1,036	157	76	5	5	1	1,530	
63	Other	CUST	(2,033)	(1,814)	(176)	(43)	(0)	(0)	(1)	-	
64	TOTAL WORKING CAPITAL		86,671	45,968	4,053	28,019	3,980	2,761	358	1,530	
65											
66	PLUS: CWIP										
67	Production	DEM	154,919	84,016	7,318	50,601	7,241	5,278	464	-	
68	Production	EGY	15,756	7,951	735	5,474	871	642	83	-	
69	Transmission	DEM	8,719	5,057	417	2,667	333	239	6	-	
70	Subtransmission	DEM	12,055	6,992	577	3,687	460	330	9	-	
71	Distribution Primary	DEM	9,825	6,115	435	2,912	306	0	56	-	
72	Distribution Secondary	DEM	(5,310)	(3,874)	(312)	(1,104)	-	-	(19)	-	
73	Distribution	CUST	9,769	3,602	546	263	17	19	4	5,318	
74	Other	CUST	24,441	21,798	2,113	520	2	0	7	-	
75	TOTAL CWIP		230,175	131,658	11,829	65,020	9,231	6,508	610	5,318	
76											
77	EQUALS: RATE BASE										
78	Production	DEM	5,483,176	2,973,656	259,023	1,790,960	256,291	186,818	16,428	-	
79	Production	EGY	412,367	208,094	19,230	143,259	22,804	16,800	2,179	-	
80	Transmission	DEM	404,511	234,622	19,354	123,720	15,445	11,084	287	-	
81	Subtransmission	DEM	439,108	254,688	21,009	134,301	16,766	12,032	311	-	
82	Distribution Primary	DEM	1,529,952	952,267	67,728	453,479	47,697	0	8,782	-	
83	Distribution Secondary	DEM	672,571	490,730	39,514	139,894	-	-	2,433	-	
84	Distribution	CUST	656,038	213,717	37,543	20,254	1,449	1,581	336	381,159	
85	Other	CUST	200,427	178,758	17,329	4,268	14	3	55	-	
86	TOTAL RATE BASE		9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159	

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF UNIT COSTS - UNTCST

PROPOSED ROR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
1	FUNCTIONALIZED REVENUE REQUIREMENTS									
2	Production	DEM	846,232	458,931	39,976	276,403	39,554	28,832	2,535	-
3	Production	EGY	104,558	52,889	4,875	36,230	5,757	4,255	552	-
4	Transmission	DEM	50,954	29,554	2,438	15,584	1,945	1,396	36	-
5	Subtransmission	DEM	64,104	37,181	3,067	19,606	2,448	1,756	45	-
6	Distribution Primary	DEM	254,046	158,122	11,246	75,299	7,920	0	1,458	-
7	Distribution Secondary	DEM	112,731	82,252	6,623	23,448	-	-	408	-
8	Distribution: MDS, Meters,Svcs,IS Equip,Lighting	CUST	137,309	57,043	10,877	6,179	460	502	104	62,145
9	Other: Meter Reading, Billing, Cust Srvc	CUST	76,183	67,923	6,588	1,622	8	2	23	(0)
10	Revenue Associated Expense & Fees	REV	5,855	3,632	373	1,239	174	93	14	324
11	TOTAL BASE REVENUE REQUIREMENTS		1,651,973	947,529	86,062	455,611	58,267	36,837	5,176	62,468
12										
13	Revenue Expense Expansion Factor		1.00356							
14	BILLING UNITS (ANNUAL)									
15	MWh Sales Related To:									
16	Production & Transmission (Factor 404)			10,290,068	950,936	7,089,279	1,148,446	847,767	107,728	
17	Distribution Primary (Factor 405)			10,290,068	950,936	7,088,228	1,148,446	-	107,728	
18	Distribution Secondary (Factor 406)			10,290,068	950,936	7,005,110	-	-	107,728	
19										
20	Billing kW Related To:									
21	Production & Transmission (Factor 401)					18,168,858	2,634,853	3,203,802		
22	Distribution Primary (Factor 402)					18,166,433	2,634,853	-		
23	Distribution Secondary (Factor 403)					17,938,641	-	-		
24			Customer Days							
25	Annual Bills (Factor 412)		280,724,055	9,229,284	894,696	220,356	744	132	2,832	
26										
27	FUNCTIONALIZED UNIT COSTS (adjusted by Revenue Expense Expansion Factor)									
28	Customer Related - $/Bill									
29	MDS, Meters, Svcs, IS Equip		$ 0.20	$ 6.20	$ 12.20	$ 28.14	$ 620.95	$ 3,818.53	$ 36.77	
30	Meter Reading, Billing, Cust Srvc		$ 0.24	$ 7.39	$ 7.39	$ 7.39	$ 11.17	$ 14.07	$ 8.20	
31	TOTAL CUSTOMER		$ 0.45	$ 13.59	$ 19.59	$ 35.53	$ 632.12	$ 3,832.60	$ 44.97	
32										
33	Production Energy (cents/kWh)			0.516	0.514	0.513	0.503	0.504	0.514	
34										
35	Capacity Related									
36	Based on MWh Sales - (cents/kWh)									
37	Production			4.476	4.219	3.913	3.456	3.413	2.362	
38	Transmission			0.651	0.581	0.498	0.384	0.373	0.076	
39	Distribution Primary			1.542	1.187	1.066	0.692	0.000	1.359	
40	Distribution Secondary			0.802	0.699	0.336	0.000	0.000	0.380	
41										
42	Based on Billing KW Demand - ($kW/month)									
43	Production Demand					$ 15.27	$ 15.07	$ 9.03		
44	Transmission Demand					$ 1.94	$ 1.67	$ 0.99		
45	Distribution Primary Demand					$ 4.16	$ 3.02	$ -		
46	Distribution Secondary Demand					$ 1.31	$ -	$ -		

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF D-E-C COSTS - DECCST

This section calculates Functionalized Revenue Requirement for Demand, Energy, Cust Costs

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
1	RATE BASE									
2	Production	DEM	5,483,176	2,973,656	259,023	1,790,960	256,291	186,818	16,428	-
3	Production	EGY	412,367	208,094	19,230	143,259	22,804	16,800	2,179	-
4	Transmission	DEM	404,511	234,622	19,354	123,720	15,445	11,084	287	-
5	Subtransmission	DEM	439,108	254,688	21,009	134,301	16,766	12,032	311	-
6	Distribution Primary	DEM	1,529,952	952,267	67,728	453,479	47,697	0	8,782	-
7	Distribution Secondary	DEM	672,571	490,730	39,514	139,894	-	-	2,433	-
8	Distribution	CUST	656,038	213,717	37,543	20,254	1,449	1,581	336	381,159
9	Other	CUST	200,427	178,758	17,329	4,268	14	3	55	-
10	TOTAL RATE BASE		9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159
11										
12	MULTIPLIED BY RATE OF RETURN		6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43
13										
14	EQUALS: RETURN ON RATE BASE									
15	Production	DEM	352,568	191,206	16,655	115,159	16,480	12,012	1,056	-
16	Production	EGY	26,515	13,380	1,237	9,212	1,466	1,080	140	-
17	Transmission	DEM	26,010	15,086	1,244	7,955	993	713	18	-
18	Subtransmission	DEM	28,235	16,376	1,351	8,636	1,078	774	20	-
19	Distribution Primary	DEM	98,376	61,231	4,355	29,159	3,067	0	565	-
20	Distribution Secondary	DEM	43,246	31,554	2,541	8,995	-	-	156	-
21	Distribution	CUST	42,183	13,742	2,414	1,302	93	102	22	24,509
22	Other	CUST	12,887	11,494	1,114	274	1	0	4	-
23	TOTAL RETURN ON RATE BASE		630,021	354,070	30,911	180,692	23,178	14,681	1,981	24,509
24										
25	PLUS: ADJ. TO INCOME TAXES (True-Ups, Adjs., ITC and PDA)									
26	Production	DEM	(68,583)	(37,194)	(3,240)	(22,401)	(3,206)	(2,337)	(205)	-
27	Production	EGY	(4,743)	(2,394)	(221)	(1,648)	(262)	(193)	(25)	-
28	Transmission	DEM	(1,517)	(880)	(73)	(464)	(58)	(42)	(1)	-
29	Subtransmission	DEM	(1,134)	(658)	(54)	(347)	(43)	(31)	(1)	-
30	Distribution Primary	DEM	(4,002)	(2,491)	(177)	(1,186)	(125)	(0)	(23)	-
31	Distribution Secondary	DEM	(1,260)	(920)	(74)	(262)	-	-	(5)	-
32	Distribution	CUST	(7,111)	(2,622)	(398)	(192)	(12)	(13)	(3)	(3,871)
33	Other	CUST	(842)	(751)	(73)	(18)	(0)	(0)	(0)	-
34	TOTAL ADJ'S TO INCOME TAXES		(89,192)	(47,908)	(4,309)	(26,518)	(3,706)	(2,616)	(263)	(3,871)
35										
36	LESS INTEREST EXPENSE									
37	Production	DEM	101,439	55,013	4,792	33,133	4,741	3,456	304	-
38	Production	EGY	7,629	3,850	356	2,650	422	311	40	-
39	Transmission	DEM	7,483	4,340	358	2,289	286	205	5	-
40	Subtransmission	DEM	8,123	4,712	389	2,485	310	223	6	-
41	Distribution Primary	DEM	28,304	17,617	1,253	8,389	882	0	162	-
42	Distribution Secondary	DEM	12,443	9,079	731	2,588	-	-	45	-
43	Distribution	CUST	12,137	4,474	679	327	21	23	5	6,607
44	Other	CUST	3,708	3,307	321	79	0	0	1	-
45	TOTAL INTEREST EXPENSE		181,266	102,391	8,878	51,940	6,663	4,218	569	6,607

RATES WITHOUT REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50% AD
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TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
46	PLUS PERMANENT TIMING DIFFERENCES									
47	Production	DEM	4,072	2,208	192	1,330	190	139	12	-
48	Production	EGY	306	155	14	106	17	12	2	-
49	Transmission	DEM	300	174	14	92	11	8	0	-
50	Subtransmission	DEM	326	189	16	100	12	9	0	-
51	Distribution Primary	DEM	1,136	707	50	337	35	0	7	-
52	Distribution Secondary	DEM	499	364	29	104	-	-	2	-
53	Distribution	CUST	487	180	27	13	1	1	0	265
54	Other	CUST	149	133	13	3	0	0	0	-
55	TOTAL PERMANENT TIMING DIFFERENCES		7,276	4,110	356	2,085	267	169	23	265
56										
57	EQUALS: OPERATING INCOME BEFORE FIT									
58	Production	DEM	186,619	101,208	8,816	60,955	8,723	6,358	559	-
59	Production	EGY	14,449	7,292	674	5,020	799	589	76	-
60	Transmission	DEM	17,310	10,040	828	5,294	661	474	12	-
61	Subtransmission	DEM	19,303	11,196	924	5,904	737	529	14	-
62	Distribution Primary	DEM	67,206	41,830	2,975	19,920	2,095	0	386	-
63	Distribution Secondary	DEM	30,043	21,920	1,765	6,249	-	-	109	-
64	Distribution	CUST	23,423	6,826	1,365	797	61	66	13	14,295
65	Other	CUST	8,487	7,569	734	181	1	0	2	-
66			366,840	207,881	18,080	104,319	13,076	8,016	1,172	14,295
67	TOTAL OPER INCOME BEFORE FIT									
68										
69	PLUS: OPER. INCOME.*(FIT/(1-FIT)									
70	Production	DEM	49,607	26,903	2,343	16,203	2,319	1,690	149	-
71	Production	EGY	3,841	1,938	179	1,334	212	156	20	-
72	Transmission	DEM	4,601	2,669	220	1,407	176	126	3	-
73	Subtransmission	DEM	5,131	2,976	246	1,569	196	141	4	-
74	Distribution Primary	DEM	17,865	11,119	791	5,295	557	0	103	-
75	Distribution Secondary	DEM	7,986	5,827	469	1,661	-	-	29	-
76	Distribution	CUST	6,226	1,814	363	212	16	18	4	3,800
77	Other	CUST	2,256	2,012	195	48	0	0	1	-
78	TOTAL FEDERAL INCOME TAX		97,514	55,260	4,806	27,730	3,476	2,131	311	3,800
79										
80	EQUALS: FEDERAL TAXABLE INCOME									
81	Production	DEM	236,226	128,111	11,159	77,158	11,042	8,048	708	-
82	Production	EGY	18,290	9,230	853	6,354	1,011	745	97	-
83	Transmission	DEM	21,911	12,709	1,048	6,702	837	600	16	-
84	Subtransmission	DEM	24,434	14,172	1,169	7,473	933	670	17	-
85	Distribution Primary	DEM	85,071	52,950	3,766	25,215	2,652	0	488	-
86	Distribution Secondary	DEM	38,029	27,747	2,234	7,910	-	-	138	-
87	Distribution	CUST	29,649	8,640	1,728	1,008	77	84	17	18,095
88	Other	CUST	10,743	9,581	929	229	1	0	3	-
89	TOTAL FEDERAL TAXABLE INCOME		464,354	263,141	22,886	132,049	16,552	10,147	1,483	18,095

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(000's)

DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
90	PLUS: STATE INC TAX = FED. TAX. INCOME *SIT/(1-SIT)									
91	Production	DEM	13,749	7,456	649	4,491	643	468	41	-
92	Production	EGY	1,065	537	50	370	59	43	6	-
93	Transmission	DEM	1,275	740	61	390	49	35	1	-
94	Subtransmission	DEM	1,422	825	68	435	54	39	1	-
95	Distribution Primary	DEM	4,951	3,082	219	1,468	154	0	28	-
96	Distribution Secondary	DEM	2,213	1,615	130	460	-	-	8	-
97	Distribution	CUST	1,726	503	101	59	4	5	1	1,053
98	Other	CUST	625	558	54	13	0	0	0	-
99	TOTAL STATE INCOME TAX		27,026	15,315	1,332	7,685	963	591	86	1,053
100										
101										
102	MINUS: PERMANENT TIMING DIFFERENCES									
103	Production	DEM	4,072	2,208	192	1,330	190	139	12	-
104	Production	EGY	306	155	14	106	17	12	2	-
105	Transmission	DEM	300	174	14	92	11	8	0	-
106	Subtransmission	DEM	326	189	16	100	12	9	0	-
107	Distribution Primary	DEM	1,136	707	50	337	35	0	7	-
108	Distribution Secondary	DEM	499	364	29	104	-	-	2	-
109	Distribution	CUST	487	180	27	13	1	1	0	265
110	Other	CUST	149	133	13	3	0	0	0	-
111	TOTAL PERMANENT TIMING DIFFERENCES		7,276	4,110	356	2,085	267	169	23	265
112										
113	PLUS INTEREST EXPENSE									
114	Production	DEM	101,439	55,013	4,792	33,133	4,741	3,456	304	-
115	Production	EGY	7,629	3,850	356	2,650	422	311	40	-
116	Transmission	DEM	7,483	4,340	358	2,289	286	205	5	-
117	Subtransmission	DEM	8,123	4,712	389	2,485	310	223	6	-
118	Distribution Primary	DEM	28,304	17,617	1,253	8,389	882	0	162	-
119	Distribution Secondary	DEM	12,443	9,079	731	2,588	-	-	45	-
120	Distribution	CUST	12,137	4,474	679	327	21	23	5	6,607
121	Other	CUST	3,708	3,307	321	79	0	0	1	-
122	TOTAL INTEREST EXPENSE		181,266	102,391	8,878	51,940	6,663	4,218	569	6,607
123										
124	EQUALS: OPERATING INCOME BEFORE TAXES									
125	Production	DEM	347,342	188,372	16,408	113,452	16,235	11,834	1,041	-
126	Production	EGY	26,677	13,462	1,244	9,268	1,475	1,087	141	-
127	Transmission	DEM	30,370	17,615	1,453	9,289	1,160	832	22	-
128	Subtransmission	DEM	33,654	19,520	1,610	10,293	1,285	922	24	-
129	Distribution Primary	DEM	117,191	72,941	5,188	34,735	3,653	0	673	-
130	Distribution Secondary	DEM	52,185	38,076	3,066	10,855	-	-	189	-
131	Distribution	CUST	43,024	13,438	2,480	1,381	101	111	23	25,490
132	Other	CUST	14,927	13,313	1,291	318	1	0	4	-
133	TOTAL OPERATING INCOME BEFORE TAXES		665,370	376,737	32,740	189,590	23,911	14,786	2,116	25,490

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LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
134	PLUS: TAXES OTHER THAN INCOME									
135	Production	DEM	51,197	27,765	2,419	16,722	2,393	1,744	153	-
136	Production	EGY	5,739	2,896	268	1,994	317	234	30	-
137	Transmission	DEM	3,580	2,076	171	1,095	137	98	3	-
138	Subtransmission	DEM	4,118	2,388	197	1,259	157	113	3	-
139	Distribution Primary	DEM	16,853	10,490	746	4,995	525	0	97	-
140	Distribution Secondary	DEM	7,340	5,355	431	1,527	-	-	27	-
141	Distribution	CUST	8,437	3,110	472	227	15	16	4	4,593
142	Other	CUST	4,329	3,861	374	92	0	0	1	-
143	TOTAL TAXES OTHER THAN INCOME		101,592	57,942	5,078	27,912	3,545	2,205	317	4,593
144										
145	PLUS: DEPREC & AMORTIZ EXPENSE									
146	Production	DEM	290,552	157,573	13,726	94,902	13,581	9,899	871	-
147	Production	EGY	30,632	15,458	1,429	10,642	1,694	1,248	162	-
148	Transmission	DEM	14,347	8,321	686	4,388	548	393	10	-
149	Subtransmission	DEM	15,521	9,002	743	4,747	593	425	11	-
150	Distribution Primary	DEM	76,341	47,516	3,379	22,628	2,380	0	438	-
151	Distribution Secondary	DEM	43,855	31,998	2,576	9,122	-	-	159	-
152	Distribution	CUST	47,757	19,058	3,756	2,174	164	179	37	22,390
153	Other	CUST	12,431	11,087	1,075	265	1	0	3	-
154	TOTAL DEPREC & AMORTIZ EXPENSE		531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390
155										
156	PLUS: LOSS ON DISPOSITION & MISC.									
157	Production	DEM	-	-	-	-	-	-	-	-
158	Production	EGY	-	-	-	-	-	-	-	-
159	Transmission	DEM	-	-	-	-	-	-	-	-
160	Subtransmission	DEM	-	-	-	-	-	-	-	-
161	Distribution Primary	DEM	-	-	-	-	-	-	-	-
162	Distribution Secondary	DEM	-	-	-	-	-	-	-	-
163	Distribution	CUST	-	-	-	-	-	-	-	-
164	Other	CUST	-	-	-	-	-	-	-	-
165	TOTAL OTHER EXPENSES		-	-	-	-	-	-	-	-
166										
167	PLUS: O & M EXPENSE									
168	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-
169	Production	EGY	41,606	20,996	1,940	14,454	2,301	1,695	220	-
170	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-
171	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-
172	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-
173	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-
174	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830
175	Other	CUST	68,841	59,810	5,825	2,575	180	94	33	324
176	TOTAL O & M EXPENSE		391,771	241,198	23,375	95,541	12,518	7,830	1,155	10,154

RATES WITHOUT REVENUE DEFICIENCY ADDITION
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LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
177	PLUS: FUEL & POWER TRANSACTIONS									
178	Production Demand	DEM	-	-	-	-	-	-	-	-
179	Production Energy	EGY	626	316	29	218	35	26	3	-
180	TOTAL FUEL & POWER TRANSACTIONS		626	316	29	218	35	26	3	-
181										
182	EQUALS: TOTAL REVENUE LESS REV TAXES									
183	Production	DEM	848,712	460,277	40,093	277,213	39,670	28,917	2,543	-
184	Production	EGY	105,282	53,129	4,910	36,576	5,822	4,289	556	-
185	Transmission	DEM	51,936	30,123	2,485	15,885	1,983	1,423	37	-
186	Subtransmission	DEM	64,413	37,361	3,082	19,701	2,459	1,765	46	-
187	Distribution Primary	DEM	269,167	167,534	11,915	79,781	8,391	0	1,545	-
188	Distribution Secondary	DEM	113,157	82,563	6,648	23,537	-	-	409	-
189	Distribution	CUST	137,601	57,150	10,893	6,186	461	503	104	62,303
190	Other	CUST	100,528	88,071	8,565	3,250	182	95	42	324
191	TOTAL TOTAL REVENUE LESS REV TAXES		1,690,796	976,208	88,591	462,128	58,969	36,992	5,282	62,627
192										
193	PLUS: ADD'L REVENUE TAXES (Bad Debt & Regulatory Assess. Fee)									
194	Production	DEM	268	40	(13)	270	29	32	2	-
195	Production	EGY	33	5	(2)	36	4	5	1	-
196	Transmission	DEM	16	3	(1)	15	1	2	0	-
197	Subtransmission	DEM	20	3	(1)	19	2	2	0	-
198	Distribution Primary	DEM	85	15	(4)	78	6	0	1	-
199	Distribution Secondary	DEM	36	7	(2)	23	-	-	0	-
200	Distribution	CUST	43	5	(3)	6	0	1	0	(62)
201	Other	CUST	32	8	(3)	3	0	0	0	(0)
202	TOTAL REVENUE TAXES		533	85	(28)	450	43	40	5	(62)
203										
204	EQUALS: TOTAL REVENUES									
205	Production	DEM	848,980	460,317	40,080	277,483	39,699	28,948	2,545	-
206	Production	EGY	105,315	53,134	4,908	36,611	5,827	4,294	557	-
207	Transmission	DEM	51,952	30,126	2,484	15,900	1,984	1,425	37	-
208	Subtransmission	DEM	64,434	37,364	3,081	19,720	2,461	1,767	46	-
209	Distribution Primary	DEM	269,252	167,549	11,912	79,859	8,398	0	1,547	-
210	Distribution Secondary	DEM	113,193	82,570	6,646	23,559	-	-	410	-
211	Distribution	CUST	137,644	57,155	10,890	6,192	461	503	104	62,241
212	Other	CUST	100,560	88,079	8,562	3,253	182	95	42	323
213	TOTAL REVENUES		1,691,329	976,293	88,563	462,578	59,012	37,032	5,287	62,564

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LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
214	LESS: REVENUE OTHER THAN SALES									
215	Production	DEM	1,851	1,004	87	605	87	63	6	-
216	Production	EGY	676	216	33	329	62	33	4	-
217	Transmission	DEM	932	540	45	285	36	26	1	-
218	Subtransmission	DEM	256	148	12	78	10	7	0	-
219	Distribution Primary	DEM	14,946	9,302	662	4,430	466	0	86	-
220	Distribution Secondary	DEM	349	254	20	73	-	-	1	-
221	Distribution	CUST	216	80	12	6	0	0	0	118
222	Other	CUST	18,521	16,523	1,601	392	0	0	5	-
223										
224	TOTAL REVENUE OTHER THAN SALES		37,746	28,068	2,473	6,196	660	129	102	118
225										
226	EQUALS: SALES REVENUE (FUNCTIONALIZED REVENUE REQUIREMEI									
227	Production	DEM	847,129	459,313	39,993	276,879	39,613	28,885	2,540	-
228	Production	EGY	104,639	52,918	4,875	36,282	5,764	4,261	553	-
229	Transmission	DEM	51,020	29,585	2,439	15,615	1,949	1,399	36	-
230	Subtransmission	DEM	64,178	37,216	3,069	19,642	2,451	1,760	46	-
231	Distribution Primary	DEM	254,307	158,246	11,250	75,429	7,932	0	1,461	-
232	Distribution Secondary	DEM	112,844	82,316	6,625	23,487	-	-	408	-
233	Distribution	CUST	137,428	57,076	10,878	6,187	461	503	104	62,123
234	Other	CUST	82,039	71,555	6,961	2,861	182	95	38	323
235										
236	TOTAL SALES REVENUE		1,653,583	948,225	86,090	456,382	58,351	36,903	5,185	62,447

RATES WITH REVENUE DEFICIENCY ADDITION
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SUMMARY - CLASS ROR'S & REVENUE REQUIREMENTS -ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
1	OPERATING REVENUES									
2	Sales Revenue	1,653,583	928,312	95,215	448,482	57,453	36,295	5,120	82,706	
3	Other Revenues	40,729	30,740	2,730	6,252	658	129	103	118	
4										
5	TOTAL OPERATING REVENUES	1,694,313	959,051	97,945	454,734	58,111	36,424	5,223	82,823	
6										
7										
8	OPERATING EXPENSES									
9	Power Transactions	626	316	29	218	35	26	3	-	
10	O&M Expense	391,771	240,849	23,336	95,898	12,546	7,864	1,159	10,120	
11	Deprec & Amortiz Expense	531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390	
12	Taxes Other than Income	101,592	57,942	5,078	27,912	3,545	2,205	317	4,593	
13	Income Taxes	36,451	18,530	4,220	6,999	517	(41)	119	6,109	
14	Gain/(Loss) on Disposal	-	-	-	-	-	-	-	-	
15										
16	TOTAL OPERATING EXPENSES	1,061,878	617,651	60,032	279,894	35,602	22,198	3,289	43,212	
17										
18										
19	NET OPERATING INCOME	632,435	341,400	37,913	174,841	22,509	14,226	1,934	39,611	
20										
21										
22	RATE BASE									
23	Plant in Service	13,418,078	7,574,297	658,507	3,804,683	483,388	304,212	42,594	550,399	
24	Plant Held for Future Use	68,034	39,340	3,165	21,161	2,679	1,476	212	-	
25	Working Capital	86,671	45,968	4,053	28,019	3,980	2,761	358	1,530	
26	Construction Work in Progress	230,175	131,658	11,829	65,020	9,231	6,508	610	5,318	
27	Less: Depreciation Reserve	4,004,807	2,284,730	196,825	1,108,748	138,811	86,640	12,964	176,089	
28										
29	TOTAL RATE BASE	9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159	
30										
31										
32										
33	RATE OF RETURN (%)	6.45	6.20	7.89	6.22	6.24	6.23	6.28	10.39	
34										
35	RATE OF RETURN INDEX	1.00	0.96	1.22	0.96	0.97	0.97	0.97	1.61	

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

SUMMARY - CLASS ROR'S & REVENUE REQUIREMENTS - ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
36	DEVELOPMENT OF REVENUE REQUIREMENTS									
37	Total Rate Base	9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159	
38	Total Cost of Capital	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	
39	(@ 9.50% ROE)									
40	Total Required Net Operating Income	630,021	354,070	30,911	180,692	23,178	14,681	1,981	24,509	
41										
42	Less: Achieved Net Operating Income	632,435	341,400	37,913	174,841	22,509	14,226	1,934	39,611	
43										
44	Equals: Return Deficiency/(Surplus)	(2,414)	12,670	(7,003)	5,851	669	455	47	(15,103)	
45	Times: Expansion Factor	1.3436	1.3436	1.3436	1.3436	1.3436	1.3436	1.3436	1.3436	
46										
47	Equals: Revenue Deficiency/ (Surplus)	(3,243)	17,023	(9,409)	7,861	899	611	63	(20,292)	
48										
49	Plus: Revenues @ Present Rates	1,694,313	959,051	97,945	454,734	58,111	36,424	5,223	82,823	
50										
51	Equals: Total Revenue Requirements	1,691,070	976,075	88,536	462,596	59,010	37,035	5,286	62,532	
52	Less: Other Revenues	(40,729)	(30,740)	(2,730)	(6,252)	(658)	(129)	(103)	(118)	
53										
54	Equals: Total Sales Revenue Requirements	1,650,340	945,335	85,806	456,344	58,352	36,907	5,183	62,414	
55										
56	Sales Revenue Requirements Index	1.00	0.98	1.11	0.98	0.98	0.98	0.99	1.33	

RATES WITH REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
COST OF SERVICE STUDY
(000's)

OPERATING REVENUES - OPREV

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
1	SALES REVENUE	REV	1,653,583	928,312	95,215	448,482	57,453	36,295	5,120	82,706	501
2											
3	MISC SERVICE REVENUE: Acct 451	CUST	21,445	19,132	1,854	453	-	-	5	-	420
4											
5	RENT REVENUE: Acct 454										
6	Production	DEM	312	169	15	102	15	11	1	-	122
7	Transmission	DEM	707	410	34	216	27	19	1	-	117
8	Subtransmission	DEM	139	81	7	43	5	4	0	-	117
9	Distribution Primary	DEM	14,488	9,018	641	4,294	452	0	83	-	105
10	Distribution Secondary	DEM	119	87	7	25	-	-	0	-	106
11	TOTAL RENT REVENUE		15,765	9,765	704	4,680	499	34	85	-	
12											
13	PLANT RELATED REVENUE: Acct 456										
14	Production	DEM	1,539	834	73	503	72	52	5	-	122
15	Production	EGY	145	73	7	51	8	6	1	-	201
16	Transmission	DEM	225	131	11	69	9	6	0	-	117
17	Transmission Firm Whsl.	REV	-	-	-	-	-	-	-	-	202
18	Subtransmission	DEM	117	68	6	36	4	3	0	-	117
19	Distribution Primary	DEM	457	285	20	135	14	0	3	-	105
20	Distribution Secondary	DEM	230	168	13	48	-	-	1	-	106
21	Distribution	CUST	216	80	12	6	0	0	0	118	907
22	Other	CUST	52	47	5	1	0	0	0	-	412
23	TOTAL PLANT RELATED REVENUE		2,981	1,685	146	848	108	68	9	118	
24											
25	ENERGY-RELATED REVENUE: Acct 456										
26	Steam & Miscellaneous	EGY	494	249	23	172	27	20	3	-	201
27	Other SO2 Whsl	EGY	-	-	-	-	-	-	-	-	202
28	Subtotal Non-Sales Revenue	SUBTOTAL	494	249	23	172	27	20	3	-	
29	Collect Fee/Sales Tax	EGY	107	54	5	37	6	4	1	-	204
30	Energy Power Sales	EGY	-	-	-	-	-	-	-	-	201
31	Unbilled Revenue	EGY	(63)	(145)	(2)	62	19	2	-	-	508
32	Subtotal Sales Revenue	SUBTOTAL	44	(91)	3	100	25	7	1	-	
33	TOTAL ENERGY RELATED REVENUE		538	159	26	271	52	27	3	-	
34											
35	TOTAL OPERATING REVENUE										
36	Sales (incl Transm Firm Whsl)	REV	1,653,583	928,312	95,215	448,482	57,453	36,295	5,120	82,706	
37	Production	DEM	1,851	1,004	87	605	87	63	6	-	
38	Production	EGY	683	232	33	322	60	33	4	-	
39	Transmission	DEM	932	540	45	285	36	26	1	-	
40	Subtransmission	DEM	256	148	12	78	10	7	0	-	
41	Distribution Primary	DEM	14,946	9,302	662	4,430	466	0	86	-	
42	Distribution Secondary	DEM	349	254	20	73	-	-	1	-	
43	Distribution	CUST	216	80	12	6	0	0	0	118	
44	Other	CUST	21,497	19,178	1,859	455	0	0	5	-	
45											
46	TOTAL OPERATING REVENUE		1,694,313	959,051	97,945	454,734	58,111	36,424	5,223	82,823	

RATES WITH REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC FACTOR
1	FUEL & POWER TRANSACTIONS										
2	Whsl Capacity & Reactive Pwr	DEM	-	-	-	-	-	-	-	-	201
3	Whsl NR SO 2 allowances	EGY	-	-	-	-	-	-	-	-	201
4	Whsl NRFuel Handling & Analysis	EGY	-	-	-	-	-	-	-	-	201
5											
6	Retail Reactive Power	DEM	-	-	-	-	-	-	-	-	122
7	Retail NRFuel Handling & Misc.	EGY	626	316	29	218	35	26	3	-	201
8											
9	Production Demand	DEM	-	-	-	-	-	-	-	-	
10	Production Energy	EGY	626	316	29	218	35	26	3	-	
11	TOTAL FUEL & POWER TRANSACTIONS O&M		626	316	29	218	35	26	3	-	
12											
13											
14	PRODUCTION O&M										
15	Production Demand	DEM	95,092	51,571	4,492	31,060	4,445	3,240	285	-	122
16	Production Demand - Solar	DEM	-	-	-	-	-	-	-	-	121
17	Production Energy	EGY	29,310	14,791	1,367	10,183	1,621	1,194	155	-	201
18	TOTAL PRODUCTION O&M		124,402	66,362	5,859	41,242	6,066	4,434	440	-	
19											
20											
21	TRANSMISSION O&M										
22	Step-Up Substations	DEM	3,435	1,863	162	1,122	161	117	10	-	122
23											
24	High-Volt Transmission	DEM	1,992	1,155	95	609	76	55	1	-	117
25											
26	Subtransmission										
27	Substations	DEM	4,111	2,384	197	1,257	157	113	3	-	117
28	LINES	DEM	1,477	857	71	452	56	40	1	-	117
29	Subtransmission		5,587	3,241	267	1,709	213	153	4	-	
30											
31	TOTAL TRANSMISSION O&M		11,015	6,259	525	3,440	450	325	16	-	

RATES WITH REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
32	DISTRIBUTION O&M										
33	Substations	DEM	5,221	3,249	231	1,547	163	0	30	-	105
34											
35	OH LINES Direct	CUST	1,267	-	-	-	-	-	-	1,267	310
36	OH LINES Primary	DEM	19,119	11,900	846	5,667	596	0	110	-	105
37	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
38	OH LINES Secondary	DEM	4,451	3,248	262	926	-	-	16	-	106
39	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
40	TOTAL OH LINES		24,837	15,148	1,108	6,593	596	0	126	1,267	
41											
42	UG LINES Direct	CUST	3	-	-	-	-	-	-	3	310
43	UG LINES Primary	DEM	6,193	3,855	274	1,836	193	0	36	-	105
44	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
45	UG LINES Secondary	DEM	472	345	28	98	-	-	2	-	106
46	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
47	TOTAL UG LINES		6,668	4,199	302	1,934	193	0	37	3	
48											
49	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
50	Transformers Primary	DEM	50	31	2	15	2	0	0	-	105
51	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
52	Transformers Secondary	DEM	254	185	15	53	-	-	1	-	106
53	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
54	TOTAL Transformers		304	217	17	68	2	0	1	-	
55											
56	Services	CUST	4,706	4,199	407	100	-	-	1	-	420
57	Meters	CUST	9,007	6,149	1,604	1,055	87	95	18	-	308
58	Interruptible Equipment	CUST	-	-	-	-	-	-	-	-	309
59	Street Lighting	CUST	3,452	-	-	-	-	-	-	3,452	310
60											
61	Distribution O&M	DEM	35,760	22,813	1,658	10,142	953	0	194	-	
62	Distribution O&M	CUST	18,435	10,348	2,010	1,155	87	95	19	4,721	
63											
64	TOTAL DISTRIBUTION O&M		54,195	33,161	3,669	11,296	1,040	95	214	4,721	
65											
66											
67	PROD, TRANS & DIST O&M										
68	Production	DEM	98,527	53,434	4,654	32,182	4,605	3,357	295	-	
69	Production	EGY	29,310	14,791	1,367	10,183	1,621	1,194	155	-	
70	Transmission	DEM	1,992	1,155	95	609	76	55	1	-	
71	Subtransmission	DEM	5,587	3,241	267	1,709	213	153	4	-	
72	Distribution Primary	DEM	30,582	19,035	1,354	9,065	953	0	176	-	
73	Distribution Secondary	DEM	5,178	3,778	304	1,077	-	-	19	-	
74	Distribution	CUST	18,435	10,348	2,010	1,155	87	95	19	4,721	
75	Other	CUST	-	-	-	-	-	-	-	-	
76	TOTAL PROD, TRANS & DIST O&M		189,612	105,781	10,052	55,979	7,556	4,853	669	4,721	

RATES WITH REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
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(000's)

OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
77	PLUS: OTHER CUSTOMER O&M										
78	Uncollectible	CUST	5,797	3,254	334	1,572	201	127	18	290	507
79	Billing & Records	CUST	29,377	26,201	2,540	626	2	0	8	-	412
80	Meter Reading	CUST	4,394	3,897	382	111	2	1	3	-	311
81	Cust Svc & Info	CUST	5,165	4,607	447	110	0	0	1	-	412
82	Sales	CUST	312	278	27	7	0	0	0	-	412
83	TOTAL OTHER CUSTOMER O&M		45,044	38,236	3,729	2,425	206	128	31	290	
84											
85	PLUS: ADMIN & GENERAL O&M (EXCL STORM ACCRUAL)										
86	Production	DEM	57,915	31,409	2,736	18,917	2,707	1,973	174	-	122
87	Production - Solar	DEM	3,180	1,725	150	1,039	149	108	10	-	121
88	Production	EGY	12,296	6,205	573	4,272	680	501	65	-	201
89	Transmission	DEM	1,647	955	79	504	63	45	1	-	117
90	Subtransmission	DEM	5,533	3,209	265	1,692	211	152	4	-	117
91	Distribution Primary	DEM	28,200	17,552	1,248	8,358	879	0	162	-	105
92	Distribution Secondary	DEM	4,599	3,356	270	957	-	-	17	-	106
93	Distribution	CUST	19,947	11,197	2,175	1,249	94	102	21	5,109	607
94	Other	CUST	23,797	21,224	2,057	507	2	0	7	-	412
95	TOTAL ADMIN & GENERAL O&M		157,115	96,832	9,555	37,494	4,785	2,882	459	5,109	
96											
97	PLUS: ADMIN & GENERAL (STORM ACCRUAL ONLY)										
98	Production	DEM	-	-	-	-	-	-	-	-	122
99	Production	EGY	-	-	-	-	-	-	-	-	204
100	Transmission	DEM	-	-	-	-	-	-	-	-	817
101	Subtransmission	DEM	-	-	-	-	-	-	-	-	817
102	Distribution Primary	DEM	-	-	-	-	-	-	-	-	105
103	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
104	Distribution	CUST	-	-	-	-	-	-	-	-	607
105	Other	CUST	-	-	-	-	-	-	-	-	412
106	TOTAL ADMIN & GENERAL STORM ACCRUAL		-	-	-	-	-	-	-	-	
107	SUBTOTAL ADMIN & GENERAL O&M		157,115	96,832	9,555	37,494	4,785	2,882	459	5,109	
108											
109	EQUALS: O&M EXP LESS FUEL & POWER TRANS										
110	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-	
111	Production	EGY	41,606	20,996	1,940	14,454	2,301	1,695	220	-	
112	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-	
113	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-	
114	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-	
115	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-	
116	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830	
117	Other	CUST	68,841	59,460	5,786	2,932	207	129	37	290	
118											
119	TOTAL O&M EXPENSE (EXCL. FUEL & POWER TRANS.)		391,771	240,849	23,336	95,898	12,546	7,864	1,159	10,120	
120											
121	EQUALS: O&M EXP PLUS FUEL & POWER TRANS										
122	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-	
123	Production	EGY	42,233	21,312	1,969	14,672	2,336	1,721	223	-	
124	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-	
125	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-	
126	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-	

RATES WITH REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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OPERATION & MAINTENANCE EXPENSES - O&M

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
127	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-	
128	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830	
129	Other	CUST	68,841	59,460	5,786	2,932	207	129	37	290	
130	TOTAL O&M EXPENSE (INCL. FUEL & POWER TRANS.)		392,398	241,165	23,365	96,116	12,580	7,889	1,163	10,120	

RATES WITH REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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(000's)

DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION DEPREC EXPENSE										
2	Production Demand	DEM	190,419	103,269	8,995	62,196	8,900	6,488	571	-	122
3	Production Demand - Solar Facilities	DEM	70,700	38,342	3,340	23,093	3,305	2,409	212	-	121
4	Production Energy	EGY	24,172	12,198	1,127	8,397	1,337	985	128	-	201
5	TOTAL PRODUCTION DEPRE EXPENSE		285,292	153,809	13,462	93,687	13,542	9,881	910	-	
6											
7											
8	TRANSMISSION DEPREC EXPENSE										
9	Step-Up Substations	DEM	4,400	2,386	208	1,437	206	150	13	-	122
10	Step-Up Substations - Solar	DEM	-	-	-	-	-	-	-	-	121
11	Step-Up Substations		4,400	2,386	208	1,437	206	150	13	-	
12											
13	High-Volt Transmission	DEM	13,062	7,576	625	3,995	499	358	9	-	117
14											
15	Subtransmission										
16	Substations	DEM	5,099	2,958	244	1,560	195	140	4	-	117
17	LINES	DEM	7,611	4,415	364	2,328	291	209	5	-	117
18	Subtransmission		12,711	7,372	608	3,888	485	348	9	-	
19											
20	TOTAL TRANSMISSION DEPREC EXPENSE		30,172	17,334	1,441	9,319	1,190	856	31	-	

RATES WITH REVENUE DEFICIENCY ADDITION
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(000's)

DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
21	DISTRIBUTION DEPREC EXPENSE										
22	Substations	DEM	9,807	6,104	434	2,907	306	0	56	-	105
23											
24	Poles Direct	CUST	2,045	-	-	-	-	-	-	2,045	310
25	Poles Primary	DEM	19,187	11,943	849	5,687	598	0	110	-	105
26	Poles Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
27	Poles Secondary	DEM	5,762	4,204	339	1,199	-	-	21	-	106
28	Poles Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
29	TOTAL POLES		26,995	16,147	1,188	6,886	598	0	131	2,045	
30											
31	OH LINES Direct	CUST	107	-	-	-	-	-	-	107	310
32	OH LINES Primary	DEM	5,930	3,691	263	1,758	185	0	34	-	105
33	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
34	OH LINES Secondary	DEM	902	658	53	188	-	-	3	-	106
35	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
36	TOTAL OH LINES		6,939	4,349	316	1,945	185	0	37	107	
37											
38	UG LINES Direct	CUST	10	-	-	-	-	-	-	10	310
39	UG LINES Primary	DEM	19,824	12,339	878	5,876	618	0	114	-	105
40	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
41	UG LINES Secondary	DEM	1,512	1,103	89	314	-	-	5	-	106
42	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
43	TOTAL UG LINES		21,346	13,442	966	6,190	618	0	119	10	
44											
45	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
46	Transformers Primary	DEM	6,446	4,012	285	1,911	201	0	37	-	105
47	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
48	Transformers Secondary	DEM	32,749	23,895	1,924	6,812	-	-	118	-	106
49	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
50	TOTAL Transformers		39,195	27,907	2,209	8,722	201	0	155	-	
51											
52	Services	CUST	5,783	5,159	500	122	-	-	1	-	420
53	Meters	CUST	15,404	10,516	2,742	1,804	148	162	31	-	308
54	Installations on Customers' Premises	CUST	-	-	-	-	-	-	-	-	309
55	Street Lighting	CUST	15,232	-	-	-	-	-	-	15,232	310
56											
57	Total Distribution Expense										
58	Distribution Expense	DEM	102,120	67,949	5,113	26,651	1,908	0	499	-	
59	Distribution Expense	CUST	38,580	15,675	3,242	1,927	148	162	33	17,393	
60											
61	TOTAL DISTRIBUTION DEPREC EXPENSE		140,700	83,624	8,356	28,577	2,056	162	532	17,393	
62											

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
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TAMPA ELECTRIC COMPANY
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(000's)

DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
63	PROD, TRANS & DIST DEPREC EXPENSE										
64	Production	DEM	265,519	143,997	12,543	86,726	12,411	9,047	796	-	
65	Production	EGY	24,172	12,198	1,127	8,397	1,337	985	128	-	
66	Transmission	DEM	13,062	7,576	625	3,995	499	358	9	-	
67	Subtransmission	DEM	12,711	7,372	608	3,888	485	348	9	-	
68	Distribution Primary	DEM	61,195	38,089	2,709	18,138	1,908	0	351	-	
69	Distribution Secondary	DEM	40,925	29,860	2,404	8,512	-	-	148	-	
70	Distribution	CUST	38,580	15,675	3,242	1,927	148	162	33	17,393	
71	Other	CUST	-	-	-	-	-	-	-	-	
72											
73	TOTAL PROD, TRANS & DIST DEPREC EXP		456,163	254,767	23,259	131,583	16,788	10,899	1,473	17,393	

RATES WITH REVENUE DEFICIENCY ADDITION
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DEPRECIATION EXPENSE - DEPRE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
74	PLUS: COMMUNICATION EQP DEPREC EXP										
75	Production	DEM	2,270	1,231	107	741	106	77	7	-	122
76	Production	EGY	564	285	26	196	31	23	3	-	201
77	Transmission	DEM	400	232	19	122	15	11	0	-	117
78	Subtransmission	DEM	322	187	15	99	12	9	0	-	117
79	Distribution Primary	DEM	2,079	1,294	92	616	65	0	12	-	105
80	Distribution Secondary	DEM	676	493	40	141	-	-	2	-	106
81	Distribution	CUST	801	295	45	22	1	2	0	436	907
82	Other	CUST	1,085	968	94	23	0	0	0	-	412
83											
84	TOTAL COMMUNICATION EQP DEPREC EXP		8,198	4,985	438	1,960	231	122	25	436	
85											
86	PLUS: TRANSPORTATION EQP DEPREC EXP										
87	Production	DEM	428	232	20	140	20	15	1	-	122
88	Production	EGY	-	-	-	-	-	-	-	-	201
89	Transmission	DEM	-	-	-	-	-	-	-	-	117
90	Subtransmission	DEM	-	-	-	-	-	-	-	-	117
91	Distribution Primary	DEM	-	-	-	-	-	-	-	-	105
92	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
93	Distribution	CUST	-	-	-	-	-	-	-	-	907
94	Other	CUST	-	-	-	-	-	-	-	-	412
95											
96	TOTAL TRANSPORTATION EQP DEPREC EXP		428	232	20	140	20	15	1	-	
97											
98	PLUS: GENERAL & INTANGIBLE DEPREC EXP										
99	Production	DEM	22,182	12,030	1,048	7,245	1,037	756	66	-	122
100	Production - Solar	DEM	152	83	7	50	7	5	0	-	121
101	Production	EGY	5,896	2,976	275	2,048	326	240	31	-	201
102	Transmission	DEM	885	513	42	271	34	24	1	-	117
103	Subtransmission	DEM	2,488	1,443	119	761	95	68	2	-	117
104	Distribution Primary	DEM	13,067	8,133	578	3,873	407	0	75	-	105
105	Distribution Secondary	DEM	2,254	1,645	132	469	-	-	8	-	106
106	Distribution	CUST	8,376	3,088	468	226	15	16	4	4,560	907
107	Other	CUST	11,346	10,119	981	242	1	0	3	-	412
108											
109	TOTAL GENERAL & INTANGIBLE DEPREC EXP		66,647	40,030	3,652	15,185	1,922	1,110	190	4,560	
110											
111	EQUALS: DEPRECIATION EXPENSE										
112	Production	DEM	290,552	157,573	13,726	94,902	13,581	9,899	871	-	
113	Production	EGY	30,632	15,458	1,429	10,642	1,694	1,248	162	-	
114	Transmission	DEM	14,347	8,321	686	4,388	548	393	10	-	
115	Subtransmission	DEM	15,521	9,002	743	4,747	593	425	11	-	
116	Distribution Primary	DEM	76,341	47,516	3,379	22,628	2,380	0	438	-	
117	Distribution Secondary	DEM	43,855	31,998	2,576	9,122	-	-	159	-	
118	Distribution	CUST	47,757	19,058	3,756	2,174	164	179	37	22,390	
119	Other	CUST	12,431	11,087	1,075	265	1	0	3	-	
120											
121	TOTAL DEPRECIATION EXPENSE		531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390	

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TAXES OTHER THAN INCOME TAXES - TXOTH

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PAYROLL TAXES										
2	Production	DEM	5,464	2,963	258	1,785	255	186	16	-	122
3	Production - Solar	DEM	-	-	-	-	-	-	-	-	121
4	Production	EGY	1,443	728	67	501	80	59	8	-	201
5	Transmission	DEM	217	126	10	66	8	6	0	-	117
6	Subtransmission	DEM	609	353	29	186	23	17	0	-	117
7	Distribution Primary	DEM	3,197	1,990	142	948	100	0	18	-	105
8	Distribution Secondary	DEM	551	402	32	115	-	-	2	-	106
9	Distribution	CUST	2,049	755	115	55	4	4	1	1,116	907
10	Other	CUST	2,776	2,476	240	59	0	0	1	-	412
11	TOTAL PAYROLL TAXES		16,305	9,793	893	3,715	470	271	47	1,116	
12											
13	PLUS: PROPERTY TAXES										
14	Production	DEM	45,179	24,502	2,134	14,757	2,112	1,539	135	-	122
15	Production	EGY	4,255	2,147	198	1,478	235	173	22	-	201
16	Transmission	DEM	3,319	1,925	159	1,015	127	91	2	-	117
17	Subtransmission	DEM	3,461	2,007	166	1,059	132	95	2	-	117
18	Distribution Primary	DEM	13,502	8,404	598	4,002	421	0	78	-	105
19	Distribution Secondary	DEM	6,720	4,903	395	1,398	-	-	24	-	106
20	Distribution	CUST	6,322	2,331	354	170	11	12	3	3,441	907
21	Other	CUST	1,533	1,367	133	33	0	0	0	-	412
22	TOTAL PROPERTY TAXES		84,291	47,586	4,136	23,912	3,038	1,910	268	3,441	
23											
24											
25	PLUS: OTHER TAXES										
26	Production	DEM	(76)	(41)	(4)	(25)	(4)	(3)	(0)	-	122
27	Production	EGY	(6)	(3)	(0)	(2)	(0)	(0)	(0)	-	201
28	Transmission	DEM	(6)	(3)	(0)	(2)	(0)	(0)	(0)	-	117
29	Subtransmission	DEM	(6)	(4)	(0)	(2)	(0)	(0)	(0)	-	117
30	Distribution Primary	DEM	(21)	(13)	(1)	(6)	(1)	(0)	(0)	-	105
31	Distribution Secondary	DEM	(9)	(7)	(1)	(2)	-	-	(0)	-	106
32	Distribution	CUST	(9)	(3)	(1)	(0)	(0)	(0)	(0)	(5)	907
33	Other	CUST	(3)	(2)	(0)	(0)	(0)	(0)	(0)	-	412
34	TOTAL OTHER TAXES		(135)	(76)	(7)	(39)	(5)	(3)	(0)	(5)	
35											
36	EQUALS: NON-REVENUE TAXES										
37	Production	DEM	50,567	27,424	2,389	16,517	2,364	1,723	152	-	
38	Production	EGY	5,692	2,872	265	1,977	315	232	30	-	
39	Transmission	DEM	3,530	2,048	169	1,080	135	97	3	-	
40	Subtransmission	DEM	4,064	2,357	194	1,243	155	111	3	-	
41	Distribution Primary	DEM	16,677	10,380	738	4,943	520	0	96	-	
42	Distribution Secondary	DEM	7,263	5,299	427	1,511	-	-	26	-	
43	Distribution	CUST	8,362	3,083	468	225	15	16	4	4,552	
44	Other	CUST	4,306	3,840	372	92	0	0	1	-	
45	TOTAL NON-REVENUE TAXES		100,461	57,303	5,022	27,588	3,503	2,179	314	4,552	

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TAXES OTHER THAN INCOME TAXES - TXOTH

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
46	REGULATORY ASSESSMENT FEE										
47	Production	DEM	629	341	30	206	29	21	2	-	122
48	Production	EGY	47	24	2	16	3	2	0	-	204
49	Transmission	DEM	50	29	2	15	2	1	0	-	117
50	Subtransmission	DEM	54	31	3	16	2	1	0	-	117
51	Distribution Primary	DEM	176	109	8	52	5	0	1	-	105
52	Distribution Secondary	DEM	77	56	5	16	-	-	0	-	106
53	Distribution	CUST	75	28	4	2	0	0	0	41	907
54	Other	CUST	23	21	2	0	0	0	0	-	412
55	TOTAL REGULATORY ASSESSMENT FEE		1,132	639	55	324	42	26	4	41	
56											
57											
58	EQUALS: TAXES OTHER THAN INCOME										
59	Production	DEM	51,197	27,765	2,419	16,722	2,393	1,744	153	-	
60	Production	EGY	5,739	2,896	268	1,994	317	234	30	-	
61	Transmission	DEM	3,580	2,076	171	1,095	137	98	3	-	
62	Subtransmission	DEM	4,118	2,388	197	1,259	157	113	3	-	
63	Distribution Primary	DEM	16,853	10,490	746	4,995	525	0	97	-	
64	Distribution Secondary	DEM	7,340	5,355	431	1,527	-	-	27	-	
65	Distribution	CUST	8,437	3,110	472	227	15	16	4	4,593	
66	Other	CUST	4,329	3,861	374	92	0	0	1	-	
67											
68	TOTAL TAXES OTHER THAN INCOME		101,592	57,942	5,078	27,912	3,545	2,205	317	4,593	

RATES WITH REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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INCOME TAXES - INCTX

Derivation of Operating Income

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	TOTAL OPERATING REVENUES										
2	Sales Revenue (incl. Transmission Firm Whsl)	REV	1,653,583	928,312	95,215	448,482	57,453	36,295	5,120	82,706	
3	Production	DEM	1,851	1,004	87	605	87	63	6	-	
4	Production	EGY	683	232	33	322	60	33	4	-	
5	Transmission	DEM	932	540	45	285	36	26	1	-	
6	Subtransmission	DEM	256	148	12	78	10	7	0	-	
7	Distribution Primary	DEM	14,946	9,302	662	4,430	466	0	86	-	
8	Distribution Secondary	DEM	349	254	20	73	-	-	1	-	
9	Distribution	CUST	216	80	12	6	0	0	0	118	
10	Other	CUST	21,497	19,178	1,859	455	0	0	5	-	
11	TOTAL OPERATING REVENUES		1,694,313	959,051	97,945	454,734	58,111	36,424	5,223	82,823	
12											
13	LESS: O&M EXPENSE										
14	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-	
15	Production	EGY	41,606	20,996	1,940	14,454	2,301	1,695	220	-	
16	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-	
17	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-	
18	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-	
19	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-	
20	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830	
21	Other	CUST	68,841	59,460	5,786	2,932	207	129	37	290	
22	TOTAL O&M EXPENSE		391,771	240,849	23,336	95,898	12,546	7,864	1,159	10,120	
23											
24	LESS: FUEL & POWER TRANSACTIONS										
25	Production Demand	DEM	-	-	-	-	-	-	-	-	
26	Production Energy	EGY	626	316	29	218	35	26	3	-	
27	TOTAL FUEL & POWER TRANSACTIONS		626	316	29	218	35	26	3	-	
28											
29	LESS: DEPRECIATION EXPENSE										
30	Production	DEM	290,552	157,573	13,726	94,902	13,581	9,899	871	-	
31	Production	EGY	30,632	15,458	1,429	10,642	1,694	1,248	162	-	
32	Transmission	DEM	14,347	8,321	686	4,388	548	393	10	-	
33	Subtransmission	DEM	15,521	9,002	743	4,747	593	425	11	-	
34	Distribution Primary	DEM	76,341	47,516	3,379	22,628	2,380	0	438	-	
35	Distribution Secondary	DEM	43,855	31,998	2,576	9,122	-	-	159	-	
36	Distribution	CUST	47,757	19,058	3,756	2,174	164	179	37	22,390	
37	Other	CUST	12,431	11,087	1,075	265	1	0	3	-	
38	TOTAL DEPRECIATION EXPENSE		531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390	

RATES WITH REVENUE DEFICIENCY ADDITION
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INCOME TAXES - INCTX

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
39	LESS: AMORTIZATION EXPENSE										
40	Production	DEM	-	-	-	-	-	-	-	-	
41	Production	EGY	-	-	-	-	-	-	-	-	
42	Transmission	DEM	-	-	-	-	-	-	-	-	
43	Subtransmission	DEM	-	-	-	-	-	-	-	-	
44	Distribution Primary	DEM	-	-	-	-	-	-	-	-	
45	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	
46	Distribution	CUST	-	-	-	-	-	-	-	-	
47	Other	CUST	-	-	-	-	-	-	-	-	
48	TOTAL AMORTIZATION EXPENSE		-	-	-	-	-	-	-	-	
49											
50	LESS: TAXES OTHER THAN INCOME										
51	Production	DEM	51,197	27,765	2,419	16,722	2,393	1,744	153	-	
52	Production	EGY	5,739	2,896	268	1,994	317	234	30	-	
53	Transmission	DEM	3,580	2,076	171	1,095	137	98	3	-	
54	Subtransmission	DEM	4,118	2,388	197	1,259	157	113	3	-	
55	Distribution Primary	DEM	16,853	10,490	746	4,995	525	0	97	-	
56	Distribution Secondary	DEM	7,340	5,355	431	1,527	-	-	27	-	
57	Distribution	CUST	8,437	3,110	472	227	15	16	4	4,593	
58	Other	CUST	4,329	3,861	374	92	0	0	1	-	
59	TOTAL TAXES OTHER THAN INCOME		101,592	57,942	5,078	27,912	3,545	2,205	317	4,593	
60											
61	LESS: LOSS ON DISPOSITION & MISC										
62	Production	DEM	-	-	-	-	-	-	-	-	122
63	Production	EGY	-	-	-	-	-	-	-	-	201
64	Transmission	DEM	-	-	-	-	-	-	-	-	117
65	Subtransmission	DEM	-	-	-	-	-	-	-	-	117
66	Distribution Primary	DEM	-	-	-	-	-	-	-	-	105
67	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
68	Distribution	CUST	-	-	-	-	-	-	-	-	907
69	Other	CUST	-	-	-	-	-	-	-	-	412
70	TOTAL OTHER EXPENSES		-	-	-	-	-	-	-	-	
71											
72	EQUALS: OPERATING INCOME										
73	Sales	REV	1,653,583	928,312	95,215	448,482	57,453	36,295	5,120	82,706	
74	Production	DEM	(499,520)	(270,901)	(23,597)	(163,157)	(23,348)	(17,019)	(1,497)	-	
75	Production	EGY	(77,921)	(39,434)	(3,633)	(26,986)	(4,287)	(3,170)	(411)	-	
76	Transmission	DEM	(20,634)	(11,968)	(987)	(6,311)	(788)	(565)	(15)	-	
77	Subtransmission	DEM	(30,504)	(17,693)	(1,459)	(9,330)	(1,165)	(836)	(22)	-	
78	Distribution Primary	DEM	(137,031)	(85,290)	(6,066)	(40,616)	(4,272)	(0)	(787)	-	
79	Distribution Secondary	DEM	(60,623)	(44,232)	(3,562)	(12,610)	-	-	(219)	-	
80	Distribution	CUST	(94,361)	(43,633)	(8,401)	(4,800)	(359)	(392)	(81)	(36,695)	
81	Other	CUST	(64,104)	(55,229)	(5,377)	(2,834)	(208)	(129)	(37)	(290)	
82	TOTAL OPERATING INCOME		668,887	359,930	42,133	181,839	23,026	14,184	2,053	45,721	

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

INCOME TAXES - INCTX

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
83	LESS: INTEREST EXPENSE										
84	Production	DEM	101,439	55,013	4,792	33,133	4,741	3,456	304	-	122
85	Production	EGY	7,629	3,850	356	2,650	422	311	40	-	201
86	Transmission	DEM	7,483	4,340	358	2,289	286	205	5	-	117
87	Subtransmission	DEM	8,123	4,712	389	2,485	310	223	6	-	117
88	Distribution Primary	DEM	28,304	17,617	1,253	8,389	882	0	162	-	105
89	Distribution Secondary	DEM	12,443	9,079	731	2,588	-	-	45	-	106
90	Distribution	CUST	12,137	4,474	679	327	21	23	5	6,607	907
91	Other	CUST	3,708	3,307	321	79	0	0	1	-	412
92	TOTAL INTEREST EXPENSE		181,266	102,391	8,878	51,940	6,663	4,218	569	6,607	
93											
94	PLUS: PERMANENT TIMING DIFFERENCES										
95	Production	DEM	4,072	2,208	192	1,330	190	139	12	-	122
96	Production	EGY	306	155	14	106	17	12	2	-	201
97	Transmission	DEM	300	174	14	92	11	8	0	-	117
98	Subtransmission	DEM	326	189	16	100	12	9	0	-	117
99	Distribution Primary	DEM	1,136	707	50	337	35	0	7	-	105
100	Distribution Secondary	DEM	499	364	29	104	-	-	2	-	106
101	Distribution	CUST	487	180	27	13	1	1	0	265	907
102	Other	CUST	149	133	13	3	0	0	0	-	412
103	TOTAL PERMANENT TIMING DIFFERENCES		7,276	4,110	356	2,085	267	169	23	265	
104											
105	EQUALS: FLORIDA TAXABLE INCOME										
106	Sales	REV	1,653,583	928,312	95,215	448,482	57,453	36,295	5,120	82,706	
107	Production	DEM	(596,886)	(323,706)	(28,197)	(194,960)	(27,899)	(20,337)	(1,788)	-	
108	Production	EGY	(85,244)	(43,130)	(3,974)	(29,530)	(4,692)	(3,468)	(450)	-	
109	Transmission	DEM	(27,817)	(16,134)	(1,331)	(8,508)	(1,062)	(762)	(20)	-	
110	Subtransmission	DEM	(38,301)	(22,215)	(1,833)	(11,714)	(1,462)	(1,049)	(27)	-	
111	Distribution Primary	DEM	(164,199)	(102,200)	(7,269)	(48,669)	(5,119)	(0)	(943)	-	
112	Distribution Secondary	DEM	(72,566)	(52,946)	(4,263)	(15,094)	-	-	(263)	-	
113	Distribution	CUST	(106,010)	(47,928)	(9,053)	(5,114)	(379)	(414)	(86)	(43,037)	
114	Other	CUST	(67,663)	(58,404)	(5,684)	(2,910)	(209)	(129)	(38)	(290)	
115	TOTAL FLORIDA TAXABLE INCOME		494,897	261,649	33,612	131,984	16,630	10,136	1,507	39,379	
116											
117	RESULTS: FLORIDA INCOME TAX @ 0.055										
118	Sales	REV	90,947	51,057	5,237	24,667	3,160	1,996	282	4,549	
119	Production	DEM	(32,829)	(17,804)	(1,551)	(10,723)	(1,534)	(1,119)	(98)	-	
120	Production	EGY	(4,688)	(2,372)	(219)	(1,624)	(258)	(191)	(25)	-	
121	Transmission	DEM	(1,530)	(887)	(73)	(468)	(58)	(42)	(1)	-	
122	Subtransmission	DEM	(2,107)	(1,222)	(101)	(644)	(80)	(58)	(1)	-	
123	Distribution Primary	DEM	(9,031)	(5,621)	(400)	(2,677)	(282)	(0)	(52)	-	
124	Distribution Secondary	DEM	(3,991)	(2,912)	(234)	(830)	-	-	(14)	-	
125	Distribution	CUST	(5,831)	(2,636)	(498)	(281)	(21)	(23)	(5)	(2,367)	
126	Other	CUST	(3,721)	(3,212)	(313)	(160)	(11)	(7)	(2)	(16)	
127	TOTAL FLORIDA INCOME TAX		27,219	14,391	1,849	7,259	915	557	83	2,166	

RATES WITH REVENUE DEFICIENCY ADDITION
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(000's)

INCOME TAXES - INCTX

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
128	EQUALS: FEDERAL TAXABLE INCOME										
129	Sales	REV	1,562,636	877,255	89,978	423,816	54,293	34,299	4,839	78,157	
130	Production	DEM	(564,058)	(305,902)	(26,646)	(184,237)	(26,365)	(19,218)	(1,690)	-	
131	Production	EGY	(80,555)	(40,757)	(3,756)	(27,906)	(4,434)	(3,277)	(425)	-	
132	Transmission	DEM	(26,287)	(15,247)	(1,258)	(8,040)	(1,004)	(720)	(19)	-	
133	Subtransmission	DEM	(36,195)	(20,993)	(1,732)	(11,070)	(1,382)	(992)	(26)	-	
134	Distribution Primary	DEM	(155,168)	(96,579)	(6,869)	(45,992)	(4,837)	(0)	(891)	-	
135	Distribution Secondary	DEM	(68,575)	(50,034)	(4,029)	(14,264)	-	-	(248)	-	
136	Distribution	CUST	(100,180)	(45,292)	(8,555)	(4,832)	(359)	(391)	(81)	(40,670)	
137	Other	CUST	(63,941)	(55,191)	(5,372)	(2,750)	(197)	(122)	(36)	(274)	
138	TOTAL FEDERAL TAXABLE INCOME		467,678	247,259	31,763	124,725	15,716	9,579	1,424	37,213	
139											
140	RESULTS: FEDERAL INCOME TAX @ 0.21										
141	Sales	REV	328,154	184,223	18,895	89,001	11,402	7,203	1,016	16,413	
142	Production	DEM	(118,452)	(64,239)	(5,596)	(38,690)	(5,537)	(4,036)	(355)	-	
143	Production	EGY	(16,917)	(8,559)	(789)	(5,860)	(931)	(688)	(89)	-	
144	Transmission	DEM	(5,520)	(3,202)	(264)	(1,688)	(211)	(151)	(4)	-	
145	Subtransmission	DEM	(7,601)	(4,409)	(364)	(2,325)	(290)	(208)	(5)	-	
146	Distribution Primary	DEM	(32,585)	(20,282)	(1,442)	(9,658)	(1,016)	(0)	(187)	-	
147	Distribution Secondary	DEM	(14,401)	(10,507)	(846)	(2,995)	-	-	(52)	-	
148	Distribution	CUST	(21,038)	(9,511)	(1,797)	(1,015)	(75)	(82)	(17)	(8,541)	
149	Other	CUST	(13,428)	(11,590)	(1,128)	(577)	(41)	(26)	(7)	(58)	
150	TOTAL FEDERAL INCOME TAX		98,212	51,924	6,670	26,192	3,300	2,012	299	7,815	
151											
152	ADJ. TO INCOME TAXES (True-ups, Excess Deferred, ITC AND PDA)										
153	Production	DEM	(68,583)	(37,194)	(3,240)	(22,401)	(3,206)	(2,337)	(205)	-	122
154	Production	EGY	(4,743)	(2,394)	(221)	(1,648)	(262)	(193)	(25)	-	201
155	Transmission	DEM	(1,396)	(810)	(67)	(427)	(53)	(38)	(1)	-	117
156	Subtransmission	DEM	(1,044)	(605)	(50)	(319)	(40)	(29)	(1)	-	117
157	Distribution Primary	DEM	(4,002)	(2,491)	(177)	(1,186)	(125)	(0)	(23)	-	105
158	Distribution Secondary	DEM	(1,260)	(920)	(74)	(262)	-	-	(5)	-	106
159	Distribution	CUST	(7,111)	(2,622)	(398)	(192)	(12)	(13)	(3)	(3,871)	907
160	Other	CUST	(842)	(751)	(73)	(18)	(0)	(0)	(0)	-	412
161	TOTAL ADJUSTMENT TO INCOME TAXES		(88,980)	(47,785)	(4,299)	(26,453)	(3,698)	(2,610)	(263)	(3,871)	
162											
163	TOTAL INCOME TAXES (FED, STATE, AND ADJUSTMENTS)										
164	Sales	REV	419,101	235,281	24,132	113,668	14,561	9,199	1,298	20,962	
165	Production	DEM	(219,864)	(119,237)	(10,386)	(71,814)	(10,277)	(7,491)	(659)	-	
166	Production	EGY	(26,348)	(13,325)	(1,228)	(9,132)	(1,451)	(1,072)	(139)	-	
167	Transmission	DEM	(8,446)	(4,899)	(404)	(2,583)	(322)	(231)	(6)	-	
168	Subtransmission	DEM	(10,751)	(6,236)	(514)	(3,288)	(410)	(295)	(8)	-	
169	Distribution Primary	DEM	(45,618)	(28,393)	(2,019)	(13,521)	(1,422)	(0)	(262)	-	
170	Distribution Secondary	DEM	(19,652)	(14,339)	(1,155)	(4,088)	-	-	(71)	-	
171	Distribution	CUST	(33,979)	(14,769)	(2,692)	(1,488)	(109)	(118)	(25)	(14,779)	
172	Other	CUST	(17,991)	(15,553)	(1,513)	(755)	(53)	(33)	(10)	(73)	
173											
174	TOTAL INCOME TAXES		36,451	18,530	4,220	6,999	517	(41)	119	6,109	

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(000's)

PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION PLANT										
2	Production Demand	DEM	4,493,529	2,436,947	212,273	1,467,714	210,034	153,099	13,463	-	122
3	Production Demand - Solar Facilities	DEM	2,068,978	1,122,056	97,738	675,787	96,707	70,492	6,199	-	121
4	Production Energy	EGY	570,340	287,813	26,597	198,139	31,541	23,236	3,013	-	201
5	TOTAL PRODUCTION PLANT		7,132,848	3,846,816	336,608	2,341,640	338,281	246,828	22,675	-	
6											
7											
8	TRANSMISSION PLANT										
9	Step-Up Substations	DEM	191,967	104,108	9,068	62,702	8,973	6,541	575	-	122
10	Step-Up Substations - Solar	DEM	-	-	-	-	-	-	-	-	121
11	Step-Up Substations		191,967	104,108	9,068	62,702	8,973	6,541	575	-	
12											
13	High-Volt Substations & LINES	DEM	499,579	289,762	23,902	152,796	19,075	13,689	354	-	117
14											
15	Subtransmission										
16	Substations	DEM	225,310	130,683	10,780	68,911	8,603	6,174	160	-	117
17	LINES	DEM	265,675	154,095	12,711	81,257	10,144	7,280	188	-	117
18	Subtransmission		490,985	284,778	23,491	150,168	18,746	13,453	348	-	
19											
20	TOTAL TRANSMISSION PLANT		1,182,531	678,648	56,462	365,666	46,794	33,683	1,277	-	

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PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
21	DISTRIBUTION PLANT										
22	Substations	DEM	368,438	229,322	16,310	109,205	11,486	0	2,115	-	105
23											
24	Poles Direct	CUST	32,074	-	-	-	-	-	-	32,074	310
25	Poles Primary	DEM	300,991	187,342	13,324	89,214	9,384	0	1,728	-	105
26	Poles Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
27	Poles Secondary	DEM	90,396	65,956	5,311	18,802	-	-	327	-	106
28	Poles Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
29	TOTAL POLES		423,461	253,297	18,635	108,016	9,384	0	2,055	32,074	
30											
31	OH LINES Direct	CUST	4,543	-	-	-	-	-	-	4,543	310
32	OH LINES Primary	DEM	251,747	156,691	11,144	74,618	7,848	0	1,445	-	105
33	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
34	OH LINES Secondary	DEM	38,298	27,943	2,250	7,966	-	-	139	-	106
35	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
36	TOTAL OH LINES		294,587	184,635	13,394	82,584	7,848	0	1,584	4,543	
37											
38	UG LINES Direct	CUST	386	-	-	-	-	-	-	386	310
39	UG LINES Primary	DEM	753,247	468,833	33,345	223,263	23,483	0	4,324	-	105
40	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
41	UG LINES Secondary	DEM	57,432	41,904	3,374	11,946	-	-	208	-	106
42	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
43	TOTAL UG LINES		811,065	510,737	36,719	235,209	23,483	0	4,532	386	
44											
45	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
46	Transformers Primary	DEM	164,150	102,170	7,267	48,654	5,117	0	942	-	105
47	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
48	Transformers Secondary	DEM	833,929	608,463	48,993	173,457	-	-	3,017	-	106
49	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
50	TOTAL Transformers		998,080	710,632	56,260	222,111	5,117	0	3,959	-	
51											
52	Services	CUST	228,413	203,776	19,749	4,830	-	-	58	-	420
53	Meters	CUST	149,852	102,300	26,678	17,553	1,443	1,574	304	-	308
54	Installations on Customers' Premises	CUST	-	0	-	-	-	-	-	-	309
55	Street Lighting	CUST	414,979	-	-	-	-	-	-	414,979	310
56											
57	Distribution Plant	DEM	2,858,628	1,888,624	141,318	757,125	57,318	0	14,244	-	
58	Distribution Plant	CUST	830,247	306,076	46,428	22,383	1,443	1,574	361	451,982	
59											
60	TOTAL DISTRIBUTION PLANT		3,688,875	2,194,700	187,745	779,508	58,761	1,574	14,605	451,982	
61											
62											
63	PROD, TRANS, & DIST PLANT										
64	Production	DEM	6,754,475	3,663,111	319,079	2,206,202	315,714	230,132	20,237	-	
65	Production	EGY	570,340	287,813	26,597	198,139	31,541	23,236	3,013	-	
66	Transmission	DEM	499,579	289,762	23,902	152,796	19,075	13,689	354	-	
67	Subtransmission	DEM	490,985	284,778	23,491	150,168	18,746	13,453	348	-	
68	Distribution Primary	DEM	1,838,573	1,144,357	81,390	544,954	57,318	0	10,554	-	

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PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
69	Distribution Secondary	DEM	1,020,055	744,266	59,928	212,171	-	-	3,690	-	
70	Distribution	CUST	830,247	306,076	46,428	22,383	1,443	1,574	361	451,982	
71	Other	CUST	-	-	-	-	-	-	-	-	
72	TOTAL PROD, TRANS, & DIST PLANT		12,004,254	6,720,164	580,816	3,486,814	443,837	282,085	38,557	451,982	

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PLANT IN SERVICE - PLTSVC

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
73	PLUS: COMMUNICATION EQUIPMENT										
74	Production	DEM	30,060	16,302	1,420	9,818	1,405	1,024	90	-	122
75	Production	EGY	7,469	3,769	348	2,595	413	304	39	-	201
76	Transmission	DEM	5,299	3,073	254	1,621	202	145	4	-	117
77	Subtransmission	DEM	4,265	2,474	204	1,305	163	117	3	-	117
78	Distribution Primary	DEM	27,531	17,136	1,219	8,160	858	0	158	-	105
79	Distribution Secondary	DEM	8,947	6,528	526	1,861	-	-	32	-	106
80	Distribution	CUST	10,610	3,911	593	286	18	20	5	5,776	907
81	Other	CUST	14,371	12,818	1,243	306	1	0	4	-	412
82	TOTAL COMMUNICATION EQUIPMENT		108,551	66,011	5,806	25,951	3,061	1,611	335	5,776	
83											
84	PLUS: TRANSPORTATION EQUIPMENT										
85	Production	DEM	7,483	4,058	353	2,444	350	255	22	-	122
86	Production	EGY	-	-	-	-	-	-	-	-	201
87	Transmission	DEM	2,560	1,485	122	783	98	70	2	-	117
88	Subtransmission	DEM	7,197	4,174	344	2,201	275	197	5	-	117
89	Distribution Primary	DEM	37,791	23,522	1,673	11,201	1,178	0	217	-	105
90	Distribution Secondary	DEM	6,519	4,757	383	1,356	-	-	24	-	106
91	Distribution	CUST	24,225	8,931	1,355	653	42	46	11	13,188	907
92	Other	CUST	32,813	29,265	2,837	699	2	0	9	-	412
93	TOTAL TRANSPORTATION EQUIPMENT		118,587	76,191	7,068	19,337	1,945	569	289	13,188	
94											
95	PLUS: GENERAL & INTANGIBLE										
96	Production	DEM	402,516	218,294	19,015	131,473	18,814	13,714	1,206	-	122
97	Production - Solar	DEM	4,620	2,506	218	1,509	216	157	14	-	121
98	Production	EGY	102,740	51,846	4,791	35,692	5,682	4,186	543	-	201
99	Transmission	DEM	15,422	8,945	738	4,717	589	423	11	-	117
100	Subtransmission	DEM	43,359	25,149	2,075	13,261	1,655	1,188	31	-	117
101	Distribution Primary	DEM	234,845	146,171	10,396	69,608	7,321	0	1,348	-	105
102	Distribution Secondary	DEM	39,277	28,658	2,308	8,170	-	-	142	-	106
103	Distribution	CUST	145,948	53,805	8,161	3,935	254	277	64	79,453	907
104	Other	CUST	197,960	176,558	17,116	4,215	14	3	54	-	412
105	TOTAL GENERAL & INTANGIBLE		1,186,687	711,931	64,817	272,580	34,545	19,947	3,412	79,453	
106											
107	PLUS: ROU LEASES										
108	Production	DEM	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	122
109											
110	EQUALS: PLANT IN SERVICE										
111	Production	DEM	7,199,154	3,904,271	340,086	2,351,447	336,499	245,283	21,569	-	
112	Production	EGY	680,548	343,428	31,737	236,427	37,635	27,726	3,595	-	
113	Transmission	DEM	522,859	303,265	25,016	159,917	19,963	14,327	371	-	
114	Subtransmission	DEM	545,806	316,575	26,114	166,935	20,840	14,956	387	-	
115	Distribution Primary	DEM	2,138,740	1,331,186	94,677	633,924	66,676	0	12,277	-	
116	Distribution Secondary	DEM	1,074,798	784,208	63,144	223,557	-	-	3,888	-	
117	Distribution	CUST	1,011,030	372,723	56,537	27,257	1,757	1,917	440	550,399	
118	Other	CUST	245,144	218,641	21,195	5,220	18	3	67	-	
119											
120	TOTAL PLANT IN SERVICE		13,418,078	7,574,297	658,507	3,804,683	483,388	304,212	42,594	550,399	

RATES WITH REVENUE DEFICIENCY ADDITION
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MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
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TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

PLANT HELD FOR FUTURE USE - PHFFU

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PLANT HELD FOR FUTURE USE										
2	Production	DEM	26,353	14,292	1,245	8,608	1,232	898	79	-	122
3	Production - Solar	DEM	-	-	-	-	-	-	-	-	121
4	Production	EGY	-	-	-	-	-	-	-	-	201
5	Transmission	DEM	10,636	6,169	509	3,253	406	291	8	-	117
6	Subtransmission	DEM	10,453	6,063	500	3,197	399	286	7	-	117
7	Distribution Primary	DEM	20,590	12,816	911	6,103	642	0	118	-	105
8	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	106
9	Distribution	CUST	-	-	-	-	-	-	-	-	907
10	Other	CUST	-	-	-	-	-	-	-	-	412
11											
12	TOTAL PLANT HELD FOR FUTURE USE		68,034	39,340	3,165	21,161	2,679	1,476	212	-	

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
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TAMPA ELECTRIC COMPANY
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION RESERVE										
2	Production Demand	DEM	1,542,785	836,689	72,881	503,917	72,112	52,564	4,622	-	122
3	Production Demand - Solar Facilities	DEM	222,986	120,930	10,534	72,833	10,423	7,597	668	-	121
4	Production Energy	EGY	293,748	148,235	13,699	102,050	16,245	11,968	1,552	-	201
5	TOTAL PRODUCTION DEPRE RESERVE		2,059,519	1,105,854	97,113	678,800	98,779	72,129	6,842	-	
6											
7											
8	TRANSMISSION RESERVE										
9	Step-Up Substations	DEM	46,016	24,955	2,174	15,030	2,151	1,568	138	-	122
10	Step-Up Substations - Solar	DEM	-	-	-	-	-	-	-	-	121
11	Step-Up Substations		46,016	24,955	2,174	15,030	2,151	1,568	138	-	
12											
13	High-Volt Transmission LINES	DEM	132,871	77,067	6,357	40,639	5,073	3,641	94	-	117
14											
15	Subtransmission										
16	Substations	DEM	43,645	25,314	2,088	13,349	1,666	1,196	31	-	117
17	LINES	DEM	72,368	41,975	3,462	22,134	2,763	1,983	51	-	117
18	Subtransmission		116,013	67,289	5,551	35,483	4,430	3,179	82	-	
19											
20	TOTAL TRANSMISSION DEPRE RESERVE		294,899	169,311	14,082	91,151	11,654	8,387	314	-	

RATES WITH REVENUE DEFICIENCY ADDITION
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
21	DISTRIBUTION RESERVE										
22	Substations	DEM	92,546	57,602	4,097	27,431	2,885	0	531	-	105
23											
24	Poles Direct	CUST	14,632	-	-	-	-	-	-	14,632	310
25	Poles Primary	DEM	137,306	85,461	6,078	40,697	4,281	0	788	-	105
26	Poles Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
27	Poles Secondary	DEM	41,237	30,088	2,423	8,577	-	-	149	-	106
28	Poles Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
29	TOTAL POLES		193,174	115,549	8,501	49,275	4,281	0	937	14,632	
30											
31	OH LINES Direct	CUST	2,332	-	-	-	-	-	-	2,332	310
32	OH LINES Primary	DEM	129,230	80,435	5,721	38,304	4,029	0	742	-	105
33	OH LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
34	OH LINES Secondary	DEM	19,659	14,344	1,155	4,089	-	-	71	-	106
35	OH LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
36	TOTAL OH LINES		151,221	94,779	6,876	42,393	4,029	0	813	2,332	
37											
38	UG LINES Direct	CUST	72	-	-	-	-	-	-	72	310
39	UG LINES Primary	DEM	141,098	87,822	6,246	41,822	4,399	0	810	-	105
40	UG LINES Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
41	UG LINES Secondary	DEM	10,758	7,850	632	2,238	-	-	39	-	106
42	UG LINES Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
43	TOTAL UG LINES		151,929	95,671	6,878	44,059	4,399	0	849	72	
44											
45	Transformers Direct	CUST	-	-	-	-	-	-	-	-	310
46	Transformers Primary	DEM	61,807	38,470	2,736	18,320	1,927	0	355	-	105
47	Transformers Primary (MDS)	CUST	-	-	-	-	-	-	-	-	418
48	Transformers Secondary	DEM	313,999	229,104	18,447	65,311	-	-	1,136	-	106
49	Transformers Secondary (MDS)	CUST	-	-	-	-	-	-	-	-	420
50	TOTAL Transformers		375,806	267,574	21,183	83,631	1,927	0	1,491	-	
51											
52	Services	CUST	143,574	128,088	12,414	3,036	-	-	36	-	420
53	Meters	CUST	25,381	17,327	4,519	2,973	244	267	51	-	308
54	Installations on Customers' Premises	CUST	-	-	-	-	-	-	-	-	309
55	Street Lighting	CUST	132,134	-	-	-	-	-	-	132,134	310
56											
57	Distribution Reserve	DEM	947,639	631,175	47,535	246,789	17,520	0	4,621	-	
58	Distribution Reserve	CUST	318,125	145,415	16,932	6,009	244	267	88	149,170	
59											
60	TOTAL DISTRIBUTION DEPRE RESERVE		1,265,764	776,589	64,467	252,798	17,765	267	4,709	149,170	
61											
62											

RATES WITH REVENUE DEFICIENCY ADDITION
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
63	PROD, TRANS, & DIST RESERVE										
64	Production	DEM	1,811,786	982,574	85,588	591,780	84,685	61,729	5,428	-	
65	Production	EGY	293,748	148,235	13,699	102,050	16,245	11,968	1,552	-	
66	Transmission	DEM	132,871	77,067	6,357	40,639	5,073	3,641	94	-	
67	Subtransmission	DEM	116,013	67,289	5,551	35,483	4,430	3,179	82	-	
68	Distribution Primary	DEM	561,987	349,790	24,878	166,573	17,520	0	3,226	-	
69	Distribution Secondary	DEM	385,653	281,385	22,657	80,216	-	-	1,395	-	
70	Distribution	CUST	318,125	145,415	16,932	6,009	244	267	88	149,170	
71	Other	CUST	-	-	-	-	-	-	-	-	
72											
73	TOTAL PROD, TRANS, & DIST DEPRE RESERVE		3,620,182	2,051,755	175,662	1,022,749	128,197	80,783	11,865	149,170	

RATES WITH REVENUE DEFICIENCY ADDITION
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ACCUMULATED RESERVE FOR DEPRECIATION - ACCDPR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
74	PLUS: COMMUNICATION EQUIPMENT										
75	Production	DEM	13,816	7,493	653	4,513	646	471	41	-	122
76	Production	EGY	3,433	1,732	160	1,193	190	140	18	-	201
77	Transmission	DEM	2,435	1,412	117	745	93	67	2	-	117
78	Subtransmission	DEM	1,960	1,137	94	600	75	54	1	-	117
79	Distribution Primary	DEM	12,653	7,876	560	3,750	394	0	73	-	105
80	Distribution Secondary	DEM	4,112	3,000	242	855	-	-	15	-	106
81	Distribution	CUST	4,876	1,798	273	131	8	9	2	2,655	907
82	Other	CUST	6,605	5,891	571	141	0	0	2	-	412
83	TOTAL COMM EQUIP DEPRE RESERVE		49,891	30,339	2,669	11,927	1,407	740	154	2,655	
84											
85	PLUS: TRANSPORTATION EQUIPMENT										
86	Production	DEM	2,681	1,454	127	876	125	91	8	-	122
87	Production	EGY	-	-	-	-	-	-	-	-	201
88	Transmission	DEM	891	517	43	273	34	24	1	-	117
89	Subtransmission	DEM	2,505	1,453	120	766	96	69	2	-	117
90	Distribution Primary	DEM	13,156	8,189	582	3,900	410	0	76	-	105
91	Distribution Secondary	DEM	2,270	1,656	133	472	-	-	8	-	106
92	Distribution	CUST	8,433	3,109	472	227	15	16	4	4,591	907
93	Other	CUST	11,423	10,188	988	243	1	0	3	-	412
94	TOTAL TRANSP EQUIP DEPRE RESERVE		41,360	26,566	2,464	6,757	681	201	101	4,591	
95											
96	PLUS: GENERAL & INTANGIBLE										
97	Production	DEM	99,691	54,065	4,709	32,562	4,660	3,397	299	-	122
98	Production - Solar	DEM	439	238	21	143	21	15	1	-	121
99	Production	EGY	25,439	12,837	1,186	8,838	1,407	1,036	134	-	201
100	Transmission	DEM	3,818	2,215	183	1,168	146	105	3	-	117
101	Subtransmission	DEM	10,736	6,227	514	3,284	410	294	8	-	117
102	Distribution Primary	DEM	58,293	36,282	2,580	17,278	1,817	0	335	-	105
103	Distribution Secondary	DEM	9,725	7,096	571	2,023	-	-	35	-	106
104	Distribution	CUST	36,137	13,322	2,021	974	63	69	16	19,673	907
105	Other	CUST	49,095	43,788	4,245	1,045	4	1	13	-	412
106	TOTAL GENERAL & INTANGIBLE		293,374	176,070	16,030	67,315	8,526	4,916	844	19,673	
107											
108	EQUALS: DEPRECIATION RESERVE										
109	Production	DEM	1,928,413	1,045,824	91,098	629,874	90,137	65,703	5,778	-	
110	Production	EGY	322,620	162,805	15,045	112,080	17,841	13,144	1,704	-	
111	Transmission	DEM	140,015	81,211	6,699	42,824	5,346	3,837	99	-	
112	Subtransmission	DEM	131,215	76,106	6,278	40,132	5,010	3,595	93	-	
113	Distribution Primary	DEM	646,089	402,136	28,601	191,501	20,142	0	3,709	-	
114	Distribution Secondary	DEM	401,759	293,137	23,603	83,566	-	-	1,453	-	
115	Distribution	CUST	367,572	163,644	19,697	7,342	330	360	109	176,089	
116	Other	CUST	67,124	59,867	5,804	1,429	5	1	18	-	
117											
118	TOTAL ACCUM DEPRECIATION RESERVE		4,004,807	2,284,730	196,825	1,108,748	138,811	86,640	12,964	176,089	

RATES WITH REVENUE DEFICIENCY ADDITION
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TAMPA ELECTRIC COMPANY
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(000's)

WORKING CAPITAL - WKCAP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	MATERIALS & SUPPLIES										
2	Production	DEM	91,095	49,403	4,303	29,754	4,258	3,104	273	-	122
3	Production	EGY	7,692	3,882	359	2,672	425	313	41	-	201
4	Transmission	DEM	6,738	3,908	322	2,061	257	185	5	-	117
5	Subtransmission	DEM	6,622	3,841	317	2,025	253	181	5	-	117
6	Distribution Primary	DEM	24,796	15,434	1,098	7,350	773	0	142	-	105
7	Distribution Secondary	DEM	13,757	10,038	808	2,861	-	-	50	-	106
8	Distribution	CUST	11,197	4,128	626	302	19	21	5	6,096	907
9	Other	CUST	-	-	-	-	-	-	-	-	412
10	TOTAL MATERIALS & SUPPLIES		161,897	90,632	7,833	47,025	5,986	3,804	520	6,096	
11											
12	PLUS: EXCLUSIONS										
13	Production	DEM	(276,878)	(150,157)	(13,080)	(90,436)	(12,942)	(9,434)	(830)	-	122
14	Production	EGY	(26,078)	(13,160)	(1,216)	(9,060)	(1,442)	(1,062)	(138)	-	201
15	Transmission	DEM	(20,443)	(11,857)	(978)	(6,253)	(781)	(560)	(14)	-	117
16	Subtransmission	DEM	(21,316)	(12,363)	(1,020)	(6,519)	(814)	(584)	(15)	-	117
17	Distribution Primary	DEM	(82,744)	(51,501)	(3,663)	(24,525)	(2,580)	(0)	(475)	-	105
18	Distribution Secondary	DEM	(41,186)	(30,050)	(2,420)	(8,567)	-	-	(149)	-	106
19	Distribution	CUST	(38,742)	(14,283)	(2,166)	(1,044)	(67)	(73)	(17)	(21,091)	907
20	Other	CUST	(9,394)	(8,378)	(812)	(200)	(1)	(0)	(3)	-	412
21	TOTAL CASH		(516,781)	(291,751)	(25,355)	(146,604)	(18,626)	(11,714)	(1,640)	(21,091)	
22											
23	PLUS: NET ADDITIONS										
24	Production	DEM	600,864	325,863	28,385	196,259	28,085	20,472	1,800	-	122
25	Production	EGY	56,593	28,559	2,639	19,661	3,130	2,306	299	-	201
26	Transmission	DEM	44,365	25,732	2,123	13,569	1,694	1,216	31	-	117
27	Subtransmission	DEM	46,258	26,830	2,213	14,148	1,766	1,268	33	-	117
28	Distribution Primary	DEM	179,567	111,765	7,949	53,224	5,598	0	1,031	-	105
29	Distribution Secondary	DEM	89,379	65,214	5,251	18,591	-	-	323	-	106
30	Distribution	CUST	84,076	30,995	4,702	2,267	146	159	37	45,770	907
31	Other	CUST	20,386	18,182	1,763	434	1	0	6	-	412
32	TOTAL NET ADDITIONS		1,121,487	633,140	55,024	318,152	40,421	25,421	3,560	45,770	
33											
34	MINUS: NET DEDUCTIONS										
35	Production	DEM	383,918	208,208	18,136	125,398	17,945	13,080	1,150	-	122
36	Production	EGY	36,160	18,248	1,686	12,562	2,000	1,473	191	-	201
37	Transmission	DEM	28,347	16,441	1,356	8,670	1,082	777	20	-	117
38	Subtransmission	DEM	29,556	17,143	1,414	9,040	1,128	810	21	-	117
39	Distribution Primary	DEM	114,733	71,412	5,079	34,007	3,577	0	659	-	105
40	Distribution Secondary	DEM	57,108	41,668	3,355	11,878	-	-	207	-	106
41	Distribution	CUST	53,720	19,804	3,004	1,448	93	102	23	29,245	907
42	Other	CUST	13,025	11,617	1,126	277	1	0	4	-	412
43	TOTAL NET DEDUCTIONS		716,567	404,541	35,157	203,281	25,827	16,242	2,274	29,245	

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(000's)

WORKING CAPITAL - WKCAP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
44	PLUS: FUEL INVENTORY										
45	Production	EGY	36,635	18,487	1,708	12,727	2,026	1,493	194	-	201
46	TOTAL FUEL INVENTORY		36,635	18,487	1,708	12,727	2,026	1,493	194	-	
47											
48	EQUALS: WORKING CAPITAL, (Incl. fuel inventory)										
49	Production	DEM	31,163	16,900	1,472	10,179	1,457	1,062	93	-	
50	Production	EGY	38,682	19,520	1,804	13,438	2,139	1,576	204	-	
51	Transmission	DEM	2,313	1,341	111	707	88	63	2	-	
52	Subtransmission	DEM	2,008	1,165	96	614	77	55	1	-	
53	Distribution Primary	DEM	6,885	4,286	305	2,041	215	0	40	-	
54	Distribution Secondary	DEM	4,842	3,533	284	1,007	-	-	18	-	
55	Distribution	CUST	2,811	1,036	157	76	5	5	1	1,530	
56	Other	CUST	(2,033)	(1,814)	(176)	(43)	(0)	(0)	(1)	-	
57											
58	TOTAL WORKING CAPITAL		86,671	45,968	4,053	28,019	3,980	2,761	358	1,530	

RATES WITH REVENUE DEFICIENCY ADDITION
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CONSTRUCTION WORK IN PROGRESS - CWIP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PRODUCTION CWIP										
2	Production Demand	DEM	106,808	57,924	5,046	34,886	4,992	3,639	320	-	122
3	Production Demand - Solar	DEM	-	-	-	-	-	-	-	-	121
4	Production Energy	EGY	3,054	1,541	142	1,061	169	124	16	-	201
5	TOTAL PRODUCTION CWIP		109,862	59,466	5,188	35,948	5,161	3,763	336	-	
6											
7											
8	TRANSMISSION CWIP										
9	Step-Up Substations	DEM	-	-	-	-	-	-	-	-	122
10	Hi-Volt Transmission	DEM	6,812	3,951	326	2,083	260	187	5	-	117
11	Subtransmission Common	DEM	6,695	3,883	320	2,048	256	183	5	-	117
12	TOTAL TRANSMISSION CWIP		13,507	7,834	646	4,131	516	370	10	-	
13											
14											
15	DISTRIBUTION CWIP										
16	Distribution Primary	DEM	(18,323)	(11,405)	(811)	(5,431)	(571)	(0)	(105)	-	105
17	Distribution Secondary	DEM	(10,166)	(7,417)	(597)	(2,115)	-	-	(37)	-	106
18	Distribution	CUST	(8,274)	(3,050)	(463)	(223)	(14)	(16)	(4)	(4,504)	907
19	TOTAL DISTRIBUTION CWIP		(36,764)	(21,873)	(1,871)	(7,769)	(586)	(16)	(146)	(4,504)	
20											
21											
22	PROD, TRANS & DIST CWIP										
23	Production	DEM	106,808	57,924	5,046	34,886	4,992	3,639	320	-	
24	Production	EGY	3,054	1,541	142	1,061	169	124	16	-	
25	Transmission	DEM	6,812	3,951	326	2,083	260	187	5	-	
26	Subtransmission	DEM	6,695	3,883	320	2,048	256	183	5	-	
27	Distribution Primary	DEM	(18,323)	(11,405)	(811)	(5,431)	(571)	(0)	(105)	-	
28	Distribution Secondary	DEM	(10,166)	(7,417)	(597)	(2,115)	-	-	(37)	-	
29	Distribution	CUST	(8,274)	(3,050)	(463)	(223)	(14)	(16)	(4)	(4,504)	
30	Other	CUST	-	-	-	-	-	-	-	-	
31	TOTAL PROD, TRANS & DIST CWIP		86,605	45,427	3,963	32,310	5,091	4,118	200	(4,504)	

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

CONSTRUCTION WORK IN PROGRESS - CWIP

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
32	PLUS: GENERAL CWIP										
33	Production	DEM	48,112	26,092	2,273	15,715	2,249	1,639	144	-	122
34	Production	EGY	12,702	6,410	592	4,413	702	517	67	-	201
35	Transmission	DEM	1,907	1,106	91	583	73	52	1	-	117
36	Subtransmission	DEM	5,360	3,109	256	1,640	205	147	4	-	117
37	Distribution Primary	DEM	28,149	17,520	1,246	8,343	878	0	162	-	105
38	Distribution Secondary	DEM	4,856	3,543	285	1,010	-	-	18	-	106
39	Distribution	CUST	18,044	6,652	1,009	486	31	34	8	9,823	907
40	Other	CUST	24,441	21,798	2,113	520	2	0	7	-	412
41	TOTAL GENERAL CWIP		143,570	86,230	7,866	32,710	4,139	2,390	410	9,823	
42											
43	EQUALS: TOTAL CWIP										
44	Production	DEM	154,919	84,016	7,318	50,601	7,241	5,278	464	-	
45	Production	EGY	15,756	7,951	735	5,474	871	642	83	-	
46	Transmission	DEM	8,719	5,057	417	2,667	333	239	6	-	
47	Subtransmission	DEM	12,055	6,992	577	3,687	460	330	9	-	
48	Distribution Primary	DEM	9,825	6,115	435	2,912	306	0	56	-	
49	Distribution Secondary	DEM	(5,310)	(3,874)	(312)	(1,104)	-	-	(19)	-	
50	Distribution	CUST	9,769	3,602	546	263	17	19	4	5,318	
51	Other	CUST	24,441	21,798	2,113	520	2	0	7	-	
52											
53	TOTAL CWIP		230,175	131,658	11,829	65,020	9,231	6,508	610	5,318	

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

NET PLANT AND RATE BASE - RBASE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
1	PLANT IN SERVICE										
2	Production	DEM	7,199,154	3,904,271	340,086	2,351,447	336,499	245,283	21,569	-	
3	Production	EGY	680,548	343,428	31,737	236,427	37,635	27,726	3,595	-	
4	Transmission	DEM	522,859	303,265	25,016	159,917	19,963	14,327	371	-	
5	Subtransmission	DEM	545,806	316,575	26,114	166,935	20,840	14,956	387	-	
6	Distribution Primary	DEM	2,138,740	1,331,186	94,677	633,924	66,676	0	12,277	-	
7	Distribution Secondary	DEM	1,074,798	784,208	63,144	223,557	-	-	3,888	-	
8	Distribution	CUST	1,011,030	372,723	56,537	27,257	1,757	1,917	440	550,399	
9	Other	CUST	245,144	218,641	21,195	5,220	18	3	67	-	
10	TOTAL PLANT IN SERVICE		13,418,078	7,574,297	658,507	3,804,683	483,388	304,212	42,594	550,399	
11											
12	PLUS: PLANT HELD FOR FUTURE USE										
13	Production	DEM	26,353	14,292	1,245	8,608	1,232	898	79	-	
14	Production	EGY	-	-	-	-	-	-	-	-	
15	Transmission	DEM	10,636	6,169	509	3,253	406	291	8	-	
16	Subtransmission	DEM	10,453	6,063	500	3,197	399	286	7	-	
17	Distribution Primary	DEM	20,590	12,816	911	6,103	642	0	118	-	
18	Distribution Secondary	DEM	-	-	-	-	-	-	-	-	
19	Distribution	CUST	-	-	-	-	-	-	-	-	
20	Other	CUST	-	-	-	-	-	-	-	-	
21	TOTAL PLANT HELD FOR FUTURE USE		68,034	39,340	3,165	21,161	2,679	1,476	212	-	
22											
23	EQUALS: TOTAL PLANT										
24	Production	DEM	7,225,507	3,918,563	341,331	2,360,055	337,730	246,181	21,648	-	
25	Production	EGY	680,548	343,428	31,737	236,427	37,635	27,726	3,595	-	
26	Transmission	DEM	533,495	309,434	25,525	163,170	20,370	14,618	378	-	
27	Subtransmission	DEM	556,259	322,638	26,614	170,132	21,239	15,242	394	-	
28	Distribution Primary	DEM	2,159,331	1,344,002	95,589	640,027	67,318	0	12,395	-	
29	Distribution Secondary	DEM	1,074,798	784,208	63,144	223,557	-	-	3,888	-	
30	Distribution	CUST	1,011,030	372,723	56,537	27,257	1,757	1,917	440	550,399	
31	Other	CUST	245,144	218,641	21,195	5,220	18	3	67	-	
32	TOTAL PLANT		13,486,112	7,613,637	661,672	3,825,844	486,067	305,687	42,806	550,399	
33											
34	LESS: DEPRECIATION RESERVE										
35	Production	DEM	1,928,413	1,045,824	91,098	629,874	90,137	65,703	5,778	-	
36	Production	EGY	322,620	162,805	15,045	112,080	17,841	13,144	1,704	-	
37	Transmission	DEM	140,015	81,211	6,699	42,824	5,346	3,837	99	-	
38	Subtransmission	DEM	131,215	76,106	6,278	40,132	5,010	3,595	93	-	
39	Distribution Primary	DEM	646,089	402,136	28,601	191,501	20,142	0	3,709	-	
40	Distribution Secondary	DEM	401,759	293,137	23,603	83,566	-	-	1,453	-	
41	Distribution	CUST	367,572	163,644	19,697	7,342	330	360	109	176,089	
42	Other	CUST	67,124	59,867	5,804	1,429	5	1	18	-	
43	TOTAL DEPRECIATION RESERVE		4,004,807	2,284,730	196,825	1,108,748	138,811	86,640	12,964	176,089	

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
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MINIMUM DISTRIBUTION SYSTEM (MDS) NOT EMPLOYED
Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

NET PLANT AND RATE BASE - RBASE

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES	ALLOC. FACTOR
44	EQUALS: NET PLANT										
45	Production	DEM	5,297,094	2,872,739	250,233	1,730,181	247,594	180,478	15,870	-	
46	Production	EGY	357,929	180,623	16,692	124,347	19,794	14,582	1,891	-	
47	Transmission	DEM	393,480	228,223	18,826	120,346	15,024	10,782	279	-	
48	Subtransmission	DEM	425,045	246,532	20,336	130,000	16,229	11,647	301	-	
49	Distribution Primary	DEM	1,513,241	941,866	66,988	448,525	47,176	0	8,687	-	
50	Distribution Secondary	DEM	673,039	491,071	39,541	139,992	-	-	2,435	-	
51	Distribution	CUST	643,458	209,079	36,840	19,915	1,427	1,557	331	374,310	
52	Other	CUST	178,020	158,774	15,392	3,791	13	2	49	-	
53	TOTAL NET PLANT		9,481,305	5,328,907	464,847	2,717,096	347,255	219,047	29,842	374,310	
54											
55	PLUS: WORKING CAPITAL										
56	Production	DEM	31,163	16,900	1,472	10,179	1,457	1,062	93	-	
57	Production	EGY	38,682	19,520	1,804	13,438	2,139	1,576	204	-	
58	Transmission	DEM	2,313	1,341	111	707	88	63	2	-	
59	Subtransmission	DEM	2,008	1,165	96	614	77	55	1	-	
60	Distribution Primary	DEM	6,885	4,286	305	2,041	215	0	40	-	
61	Distribution Secondary	DEM	4,842	3,533	284	1,007	-	-	18	-	
62	Distribution	CUST	2,811	1,036	157	76	5	5	1	1,530	
63	Other	CUST	(2,033)	(1,814)	(176)	(43)	(0)	(0)	(1)	-	
64	TOTAL WORKING CAPITAL		86,671	45,968	4,053	28,019	3,980	2,761	358	1,530	
65											
66	PLUS: CWIP										
67	Production	DEM	154,919	84,016	7,318	50,601	7,241	5,278	464	-	
68	Production	EGY	15,756	7,951	735	5,474	871	642	83	-	
69	Transmission	DEM	8,719	5,057	417	2,667	333	239	6	-	
70	Subtransmission	DEM	12,055	6,992	577	3,687	460	330	9	-	
71	Distribution Primary	DEM	9,825	6,115	435	2,912	306	0	56	-	
72	Distribution Secondary	DEM	(5,310)	(3,874)	(312)	(1,104)	-	-	(19)	-	
73	Distribution	CUST	9,769	3,602	546	263	17	19	4	5,318	
74	Other	CUST	24,441	21,798	2,113	520	2	0	7	-	
75	TOTAL CWIP		230,175	131,658	11,829	65,020	9,231	6,508	610	5,318	
76											
77	EQUALS: RATE BASE										
78	Production	DEM	5,483,176	2,973,656	259,023	1,790,960	256,291	186,818	16,428	-	
79	Production	EGY	412,367	208,094	19,230	143,259	22,804	16,800	2,179	-	
80	Transmission	DEM	404,511	234,622	19,354	123,720	15,445	11,084	287	-	
81	Subtransmission	DEM	439,108	254,688	21,009	134,301	16,766	12,032	311	-	
82	Distribution Primary	DEM	1,529,952	952,267	67,728	453,479	47,697	0	8,782	-	
83	Distribution Secondary	DEM	672,571	490,730	39,514	139,894	-	-	2,433	-	
84	Distribution	CUST	656,038	213,717	37,543	20,254	1,449	1,581	336	381,159	
85	Other	CUST	200,427	178,758	17,329	4,268	14	3	55	-	
86	TOTAL RATE BASE		9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159	

RATES WITH REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF UNIT COSTS - UNTCST

PROPOSED ROR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
1	FUNCTIONALIZED REVENUE REQUIREMENTS									
2	Production	DEM	846,232	458,931	39,976	276,403	39,554	28,832	2,535	-
3	Production	EGY	104,551	52,873	4,874	36,237	5,760	4,255	552	-
4	Transmission	DEM	51,116	29,648	2,446	15,634	1,952	1,401	36	-
5	Subtransmission	DEM	64,225	37,251	3,073	19,643	2,452	1,760	46	-
6	Distribution Primary	DEM	254,046	158,122	11,246	75,299	7,920	0	1,458	-
7	Distribution Secondary	DEM	112,731	82,252	6,623	23,448	-	-	408	-
8	Distribution: MDS, Meters,Svcs,IS Equip,Lighting	CUST	137,309	57,043	10,877	6,179	460	502	104	62,145
9	Other: Meter Reading, Billing, Cust Srvc	CUST	73,211	65,268	6,331	1,578	8	2	23	(0)
10	Revenue Associated Expense & Fees	REV	5,819	3,279	334	1,574	201	127	18	290
11	TOTAL BASE REVENUE REQUIREMENTS		1,649,241	944,669	85,779	455,996	58,307	36,879	5,180	62,434
12										
13	Revenue Expense Expansion Factor		1.00354							
14	BILLING UNITS (ANNUAL)									
15	MWh Sales Related To:									
16	Production & Transmission (Factor 404)			10,290,068	950,936	7,089,279	1,148,446	847,767	107,728	
17	Distribution Primary (Factor 405)			10,290,068	950,936	7,088,228	1,148,446	-	107,728	
18	Distribution Secondary (Factor 406)			10,290,068	950,936	7,005,110	-	-	107,728	
19										
20	Billing kW Related To:									
21	Production & Transmission (Factor 401)					18,168,858	2,634,853	3,203,802		
22	Distribution Primary (Factor 402)					18,166,433	2,634,853	-		
23	Distribution Secondary (Factor 403)					17,938,641	-	-		
24			Customer Days							
25	Annual Bills (Factor 412)		280,724,055	9,229,284	894,696	220,356	744	132	2,832	
26										
27	FUNCTIONALIZED UNIT COSTS (adjusted by Revenue Expense Expansion Factor)									
28	Customer Related - $/Bill									
29	MDS, Meters, Svcs, IS Equip		$ 0.20	$ 6.20	$ 12.20	$ 28.14	$ 620.94	$ 3,818.47	$ 36.77	
30	Meter Reading, Billing, Cust Srvc		$ 0.23	$ 7.10	$ 7.10	$ 7.19	$ 11.01	$ 13.33	$ 8.06	
31	TOTAL CUSTOMER		$ 0.44	$ 13.30	$ 19.30	$ 35.33	$ 631.95	$ 3,831.80	$ 44.82	
32										
33	Production Energy (cents/kWh)			0.516	0.514	0.513	0.503	0.504	0.514	
34										
35	Capacity Related									
36	Based on MWh Sales - (cents/kWh)									
37	Production			4.476	4.219	3.913	3.456	3.413	2.362	
38	Transmission			0.652	0.582	0.499	0.385	0.374	0.076	
39	Distribution Primary			1.542	1.187	1.066	0.692	0.000	1.358	
40	Distribution Secondary			0.802	0.699	0.336	0.000	0.000	0.380	
41										
42	Based on Billing KW Demand - ($kW/month)									
43	Production Demand					$ 15.27	$ 15.07	$ 9.03		
44	Transmission Demand					$ 1.95	$ 1.68	$ 0.99		
45	Distribution Primary Demand					$ 4.16	$ 3.02	$ -		
46	Distribution Secondary Demand					$ 1.31	$ -	$ -		

RATES WITH REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF D-E-C COSTS - DECCST

This section calculates Functionalized Revenue
Requirement for Demand, Energy, Cust Costs

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
1	RATE BASE									
2	Production	DEM	5,483,176	2,973,656	259,023	1,790,960	256,291	186,818	16,428	-
3	Production	EGY	412,367	208,094	19,230	143,259	22,804	16,800	2,179	-
4	Transmission	DEM	404,511	234,622	19,354	123,720	15,445	11,084	287	-
5	Subtransmission	DEM	439,108	254,688	21,009	134,301	16,766	12,032	311	-
6	Distribution Primary	DEM	1,529,952	952,267	67,728	453,479	47,697	0	8,782	-
7	Distribution Secondary	DEM	672,571	490,730	39,514	139,894	-	-	2,433	-
8	Distribution	CUST	656,038	213,717	37,543	20,254	1,449	1,581	336	381,159
9	Other	CUST	200,427	178,758	17,329	4,268	14	3	55	-
10	TOTAL RATE BASE		9,798,150	5,506,533	480,730	2,810,135	360,466	228,317	30,811	381,159
11										
12	MULTIPLIED BY RATE OF RETURN		6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43
13										
14	EQUALS: RETURN ON RATE BASE									
15	Production	DEM	352,568	191,206	16,655	115,159	16,480	12,012	1,056	-
16	Production	EGY	26,515	13,380	1,237	9,212	1,466	1,080	140	-
17	Transmission	DEM	26,010	15,086	1,244	7,955	993	713	18	-
18	Subtransmission	DEM	28,235	16,376	1,351	8,636	1,078	774	20	-
19	Distribution Primary	DEM	98,376	61,231	4,355	29,159	3,067	0	565	-
20	Distribution Secondary	DEM	43,246	31,554	2,541	8,995	-	-	156	-
21	Distribution	CUST	42,183	13,742	2,414	1,302	93	102	22	24,509
22	Other	CUST	12,887	11,494	1,114	274	1	0	4	-
23	TOTAL RETURN ON RATE BASE		630,021	354,070	30,911	180,692	23,178	14,681	1,981	24,509
24										
25	PLUS: ADJ. TO INCOME TAXES (True-Ups, Adjs., ITC and PDA)									
26	Production	DEM	(68,583)	(37,194)	(3,240)	(22,401)	(3,206)	(2,337)	(205)	-
27	Production	EGY	(4,743)	(2,394)	(221)	(1,648)	(262)	(193)	(25)	-
28	Transmission	DEM	(1,396)	(810)	(67)	(427)	(53)	(38)	(1)	-
29	Subtransmission	DEM	(1,044)	(605)	(50)	(319)	(40)	(29)	(1)	-
30	Distribution Primary	DEM	(4,002)	(2,491)	(177)	(1,186)	(125)	(0)	(23)	-
31	Distribution Secondary	DEM	(1,260)	(920)	(74)	(262)	-	-	(5)	-
32	Distribution	CUST	(7,111)	(2,622)	(398)	(192)	(12)	(13)	(3)	(3,871)
33	Other	CUST	(842)	(751)	(73)	(18)	(0)	(0)	(0)	-
34	TOTAL ADJ'S TO INCOME TAXES		(88,980)	(47,785)	(4,299)	(26,453)	(3,698)	(2,610)	(263)	(3,871)
35										
36	LESS INTEREST EXPENSE									
37	Production	DEM	101,439	55,013	4,792	33,133	4,741	3,456	304	-
38	Production	EGY	7,629	3,850	356	2,650	422	311	40	-
39	Transmission	DEM	7,483	4,340	358	2,289	286	205	5	-
40	Subtransmission	DEM	8,123	4,712	389	2,485	310	223	6	-
41	Distribution Primary	DEM	28,304	17,617	1,253	8,389	882	0	162	-
42	Distribution Secondary	DEM	12,443	9,079	731	2,588	-	-	45	-
43	Distribution	CUST	12,137	4,474	679	327	21	23	5	6,607
44	Other	CUST	3,708	3,307	321	79	0	0	1	-
45	TOTAL INTEREST EXPENSE		181,266	102,391	8,878	51,940	6,663	4,218	569	6,607

RATES WITH REVENUE DEFICIENCY ADDITION
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
46	PLUS PERMANENT TIMING DIFFERENCES									
47	Production	DEM	4,072	2,208	192	1,330	190	139	12	-
48	Production	EGY	306	155	14	106	17	12	2	-
49	Transmission	DEM	300	174	14	92	11	8	0	-
50	Subtransmission	DEM	326	189	16	100	12	9	0	-
51	Distribution Primary	DEM	1,136	707	50	337	35	0	7	-
52	Distribution Secondary	DEM	499	364	29	104	-	-	2	-
53	Distribution	CUST	487	180	27	13	1	1	0	265
54	Other	CUST	149	133	13	3	0	0	0	-
55	TOTAL PERMANENT TIMING DIFFERENCES		7,276	4,110	356	2,085	267	169	23	265
56										
57	EQUALS: OPERATING INCOME BEFORE FIT									
58	Production	DEM	186,619	101,208	8,816	60,955	8,723	6,358	559	-
59	Production	EGY	14,449	7,292	674	5,020	799	589	76	-
60	Transmission	DEM	17,431	10,110	834	5,331	666	478	12	-
61	Subtransmission	DEM	19,394	11,248	928	5,932	740	531	14	-
62	Distribution Primary	DEM	67,206	41,830	2,975	19,920	2,095	0	386	-
63	Distribution Secondary	DEM	30,043	21,920	1,765	6,249	-	-	109	-
64	Distribution	CUST	23,423	6,826	1,365	797	61	66	13	14,295
65	Other	CUST	8,487	7,569	734	181	1	0	2	-
66			367,051	208,004	18,090	104,384	13,084	8,022	1,172	14,295
67	TOTAL OPER INCOME BEFORE FIT									
68										
69	PLUS: OPER. INCOME.*(FIT/(1-FIT)									
70	Production	DEM	49,607	26,903	2,343	16,203	2,319	1,690	149	-
71	Production	EGY	3,841	1,938	179	1,334	212	156	20	-
72	Transmission	DEM	4,634	2,688	222	1,417	177	127	3	-
73	Subtransmission	DEM	5,155	2,990	247	1,577	197	141	4	-
74	Distribution Primary	DEM	17,865	11,119	791	5,295	557	0	103	-
75	Distribution Secondary	DEM	7,986	5,827	469	1,661	-	-	29	-
76	Distribution	CUST	6,226	1,814	363	212	16	18	4	3,800
77	Other	CUST	2,256	2,012	195	48	0	0	1	-
78	TOTAL FEDERAL INCOME TAX		97,571	55,292	4,809	27,748	3,478	2,132	311	3,800
79										
80	EQUALS: FEDERAL TAXABLE INCOME									
81	Production	DEM	236,226	128,111	11,159	77,158	11,042	8,048	708	-
82	Production	EGY	18,290	9,230	853	6,354	1,011	745	97	-
83	Transmission	DEM	22,065	12,798	1,056	6,748	842	605	16	-
84	Subtransmission	DEM	24,549	14,239	1,175	7,508	937	673	17	-
85	Distribution Primary	DEM	85,071	52,950	3,766	25,215	2,652	0	488	-
86	Distribution Secondary	DEM	38,029	27,747	2,234	7,910	-	-	138	-
87	Distribution	CUST	29,649	8,640	1,728	1,008	77	84	17	18,095
88	Other	CUST	10,743	9,581	929	229	1	0	3	-
89	TOTAL FEDERAL TAXABLE INCOME		464,622	263,296	22,899	132,131	16,562	10,155	1,483	18,095

RATES WITH REVENUE DEFICIENCY ADDITION
PROD. CAP. ALLOC. METHOD: 12 CP & 50 AD
PROJECTED CALENDAR YEAR 2025; FULLY ADJUSTED DATA
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Tampa Electric 2025 OB Budget

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
90	PLUS: STATE INC TAX = FED. TAX. INCOME *SIT/(1-SIT)									
91	Production	DEM	13,749	7,456	649	4,491	643	468	41	-
92	Production	EGY	1,065	537	50	370	59	43	6	-
93	Transmission	DEM	1,284	745	61	393	49	35	1	-
94	Subtransmission	DEM	1,429	829	68	437	55	39	1	-
95	Distribution Primary	DEM	4,951	3,082	219	1,468	154	0	28	-
96	Distribution Secondary	DEM	2,213	1,615	130	460	-	-	8	-
97	Distribution	CUST	1,726	503	101	59	4	5	1	1,053
98	Other	CUST	625	558	54	13	0	0	0	-
99	TOTAL STATE INCOME TAX		27,041	15,324	1,333	7,690	964	591	86	1,053
100										
101										
102	MINUS: PERMANENT TIMING DIFFERENCES									
103	Production	DEM	4,072	2,208	192	1,330	190	139	12	-
104	Production	EGY	306	155	14	106	17	12	2	-
105	Transmission	DEM	300	174	14	92	11	8	0	-
106	Subtransmission	DEM	326	189	16	100	12	9	0	-
107	Distribution Primary	DEM	1,136	707	50	337	35	0	7	-
108	Distribution Secondary	DEM	499	364	29	104	-	-	2	-
109	Distribution	CUST	487	180	27	13	1	1	0	265
110	Other	CUST	149	133	13	3	0	0	0	-
111	TOTAL PERMANENT TIMING DIFFERENCES		7,276	4,110	356	2,085	267	169	23	265
112										
113	PLUS INTEREST EXPENSE									
114	Production	DEM	101,439	55,013	4,792	33,133	4,741	3,456	304	-
115	Production	EGY	7,629	3,850	356	2,650	422	311	40	-
116	Transmission	DEM	7,483	4,340	358	2,289	286	205	5	-
117	Subtransmission	DEM	8,123	4,712	389	2,485	310	223	6	-
118	Distribution Primary	DEM	28,304	17,617	1,253	8,389	882	0	162	-
119	Distribution Secondary	DEM	12,443	9,079	731	2,588	-	-	45	-
120	Distribution	CUST	12,137	4,474	679	327	21	23	5	6,607
121	Other	CUST	3,708	3,307	321	79	0	0	1	-
122	TOTAL INTEREST EXPENSE		181,266	102,391	8,878	51,940	6,663	4,218	569	6,607
123										
124	EQUALS: OPERATING INCOME BEFORE TAXES									
125	Production	DEM	347,341	188,371	16,408	113,452	16,235	11,834	1,041	-
126	Production	EGY	26,677	13,462	1,244	9,268	1,475	1,087	141	-
127	Transmission	DEM	30,532	17,709	1,461	9,338	1,166	837	22	-
128	Subtransmission	DEM	33,775	19,590	1,616	10,330	1,290	925	24	-
129	Distribution Primary	DEM	117,191	72,941	5,188	34,735	3,653	0	673	-
130	Distribution Secondary	DEM	52,185	38,076	3,066	10,855	-	-	189	-
131	Distribution	CUST	43,024	13,438	2,480	1,381	101	111	23	25,490
132	Other	CUST	14,927	13,313	1,291	318	1	0	4	-
133	TOTAL OPERATING INCOME BEFORE TAXES		665,653	376,901	32,753	189,677	23,922	14,794	2,116	25,490

RATES WITH REVENUE DEFICIENCY ADDITION
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(000's)

DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
134	PLUS: TAXES OTHER THAN INCOME									
135	Production	DEM	51,197	27,765	2,419	16,722	2,393	1,744	153	-
136	Production	EGY	5,739	2,896	268	1,994	317	234	30	-
137	Transmission	DEM	3,580	2,076	171	1,095	137	98	3	-
138	Subtransmission	DEM	4,118	2,388	197	1,259	157	113	3	-
139	Distribution Primary	DEM	16,853	10,490	746	4,995	525	0	97	-
140	Distribution Secondary	DEM	7,340	5,355	431	1,527	-	-	27	-
141	Distribution	CUST	8,437	3,110	472	227	15	16	4	4,593
142	Other	CUST	4,329	3,861	374	92	0	0	1	-
143	TOTAL TAXES OTHER THAN INCOME		101,592	57,942	5,078	27,912	3,545	2,205	317	4,593
144										
145	PLUS: DEPREC & AMORTIZ EXPENSE									
146	Production	DEM	290,552	157,573	13,726	94,902	13,581	9,899	871	-
147	Production	EGY	30,632	15,458	1,429	10,642	1,694	1,248	162	-
148	Transmission	DEM	14,347	8,321	686	4,388	548	393	10	-
149	Subtransmission	DEM	15,521	9,002	743	4,747	593	425	11	-
150	Distribution Primary	DEM	76,341	47,516	3,379	22,628	2,380	0	438	-
151	Distribution Secondary	DEM	43,855	31,998	2,576	9,122	-	-	159	-
152	Distribution	CUST	47,757	19,058	3,756	2,174	164	179	37	22,390
153	Other	CUST	12,431	11,087	1,075	265	1	0	3	-
154	TOTAL DEPREC & AMORTIZ EXPENSE		531,436	300,014	27,369	148,867	18,960	12,145	1,690	22,390
155										
156	PLUS: LOSS ON DISPOSITION & MISC.									
157	Production	DEM	-	-	-	-	-	-	-	-
158	Production	EGY	-	-	-	-	-	-	-	-
159	Transmission	DEM	-	-	-	-	-	-	-	-
160	Subtransmission	DEM	-	-	-	-	-	-	-	-
161	Distribution Primary	DEM	-	-	-	-	-	-	-	-
162	Distribution Secondary	DEM	-	-	-	-	-	-	-	-
163	Distribution	CUST	-	-	-	-	-	-	-	-
164	Other	CUST	-	-	-	-	-	-	-	-
165	TOTAL OTHER EXPENSES		-	-	-	-	-	-	-	-
166										
167	PLUS: O & M EXPENSE									
168	Production	DEM	159,622	86,567	7,540	52,137	7,461	5,438	478	-
169	Production	EGY	41,606	20,996	1,940	14,454	2,301	1,695	220	-
170	Transmission	DEM	3,639	2,111	174	1,113	139	100	3	-
171	Subtransmission	DEM	11,121	6,450	532	3,401	425	305	8	-
172	Distribution Primary	DEM	58,782	36,587	2,602	17,423	1,833	0	337	-
173	Distribution Secondary	DEM	9,777	7,134	574	2,034	-	-	35	-
174	Distribution	CUST	38,382	21,544	4,186	2,404	181	197	40	9,830
175	Other	CUST	68,841	59,460	5,786	2,932	207	129	37	290
176	TOTAL O & M EXPENSE		391,771	240,849	23,336	95,898	12,546	7,864	1,159	10,120

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DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
177	PLUS: FUEL & POWER TRANSACTIONS									
178	Production Demand	DEM	-	-	-	-	-	-	-	-
179	Production Energy	EGY	626	316	29	218	35	26	3	-
180	TOTAL FUEL & POWER TRANSACTIONS		626	316	29	218	35	26	3	-
181										
182	EQUALS: TOTAL REVENUE LESS REV TAXES									
183	Production	DEM	848,712	460,277	40,093	277,213	39,670	28,917	2,543	-
184	Production	EGY	105,282	53,129	4,910	36,576	5,822	4,289	556	-
185	Transmission	DEM	52,098	30,217	2,493	15,934	1,989	1,428	37	-
186	Subtransmission	DEM	64,534	37,431	3,088	19,738	2,464	1,768	46	-
187	Distribution Primary	DEM	269,167	167,534	11,915	79,781	8,391	0	1,545	-
188	Distribution Secondary	DEM	113,157	82,563	6,648	23,537	-	-	409	-
189	Distribution	CUST	137,601	57,150	10,893	6,186	461	503	104	62,303
190	Other	CUST	100,528	87,721	8,526	3,607	210	129	46	290
191	TOTAL TOTAL REVENUE LESS REV TAXES		1,691,079	976,022	88,565	462,572	59,007	37,033	5,286	62,593
192										
193	PLUS: ADD'L REVENUE TAXES (Bad Debt & Regulatory Assess. Fee)									
194	Production	DEM	(5)	25	(13)	15	2	1	0	-
195	Production	EGY	(1)	3	(2)	2	0	0	0	-
196	Transmission	DEM	(0)	2	(1)	1	0	0	0	-
197	Subtransmission	DEM	(0)	2	(1)	1	0	0	0	-
198	Distribution Primary	DEM	(2)	9	(4)	4	0	0	0	-
199	Distribution Secondary	DEM	(1)	4	(2)	1	-	-	0	-
200	Distribution	CUST	(1)	3	(4)	0	0	0	0	(62)
201	Other	CUST	(1)	5	(3)	0	0	0	0	(0)
202	TOTAL REVENUE TAXES		(10)	53	(29)	24	3	2	0	(63)
203										
204	EQUALS: TOTAL REVENUES									
205	Production	DEM	848,707	460,301	40,080	277,228	39,672	28,918	2,543	-
206	Production	EGY	105,281	53,132	4,908	36,578	5,823	4,290	556	-
207	Transmission	DEM	52,097	30,219	2,492	15,935	1,989	1,428	37	-
208	Subtransmission	DEM	64,534	37,433	3,087	19,739	2,464	1,768	46	-
209	Distribution Primary	DEM	269,166	167,543	11,912	79,785	8,392	0	1,545	-
210	Distribution Secondary	DEM	113,156	82,568	6,646	23,538	-	-	409	-
211	Distribution	CUST	137,600	57,153	10,890	6,187	461	503	104	62,241
212	Other	CUST	100,528	87,726	8,523	3,607	210	129	46	290
213	TOTAL REVENUES		1,691,069	976,075	88,536	462,596	59,010	37,035	5,286	62,531

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TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
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DERIVATION OF D-E-C COSTS - DECCST

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLDPR	GSLDSU	LS ENERGY	LS FACILITIES
214	LESS: REVENUE OTHER THAN SALES									
215	Production	DEM	1,851	1,004	87	605	87	63	6	-
216	Production	EGY	683	232	33	322	60	33	4	-
217	Transmission	DEM	932	540	45	285	36	26	1	-
218	Subtransmission	DEM	256	148	12	78	10	7	0	-
219	Distribution Primary	DEM	14,946	9,302	662	4,430	466	0	86	-
220	Distribution Secondary	DEM	349	254	20	73	-	-	1	-
221	Distribution	CUST	216	80	12	6	0	0	0	118
222	Other	CUST	21,497	19,178	1,859	455	0	0	5	-
223										
224	TOTAL REVENUE OTHER THAN SALES		40,729	30,740	2,730	6,252	658	129	103	118
225										
226	EQUALS: SALES REVENUE (FUNCTIONALIZED REVENUE REQUIREM									
227	Production	DEM	846,856	459,298	39,992	276,623	39,585	28,855	2,537	-
228	Production	EGY	104,598	52,900	4,875	36,256	5,762	4,257	552	-
229	Transmission	DEM	51,165	29,678	2,447	15,650	1,954	1,402	36	-
230	Subtransmission	DEM	64,278	37,285	3,074	19,661	2,454	1,761	46	-
231	Distribution Primary	DEM	254,220	158,241	11,250	75,356	7,926	0	1,459	-
232	Distribution Secondary	DEM	112,808	82,313	6,625	23,465	-	-	408	-
233	Distribution	CUST	137,384	57,074	10,877	6,181	461	502	104	62,123
234	Other	CUST	79,030	68,547	6,664	3,152	210	129	41	290
235										
236	TOTAL SALES REVENUE		1,650,340	945,335	85,806	456,344	58,352	36,907	5,183	62,413

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.	Type of data shown:
COMPANY: TAMPA ELECTRIC COMPANY		XX Projected Test year Ended 12/31/2025
		Projected Prior Year Ended 12/31/2024
		Historical Prior Year Ended 12/31/2023
DOCKET No. 20240026-EI		Witness: K. Rábago

Rate Schedule RS, RSVP-1

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Revenue Difference	Revenue Percent Increase
1											
2	Basic Service Charge:										
3	Standard	279,108,556	Days	$ 0.71	198,167,075	279,108,556	Days	$ 0.43	120,016,679	(78,150,396)	-39.4366%
4	RSVP-1	1,616,968	Days	$ 0.71	1,148,047	1,616,968	Days	$ 0.43	695,296	(452,751)	-39.4366%
5	Total	280,725,524	Total Days		199,315,122	280,725,524	Total Days		120,711,975	(78,603,147)	-39.4366%
6											
7											
8											
9	Energy Charge:										
10	Standard										
11	First 1,000 kWh	7,076,568,254	kWh	$ 0.06650	470,591,789	7,076,568,254	kWh	$ 0.07535	533,197,303	62,605,515	13.3036%
12	All additional kWh	3,133,088,980	kWh	$ 0.07802	244,443,602	3,133,088,980	kWh	$ 0.08535	267,399,353	22,955,751	9.3910%
13	RSVP-1	80,411,220	kWh	$ 0.07012	5,638,435	80,411,220	kWh	$ 0.07945	6,388,548	750,113	13.3036%
14	SSR-1 (Sun Select)**	7,490,718	kWh	$ 0.06300	471,915	7,490,718	kWh	$ 0.06300	471,915	-	0.0000%
15	Total	10,290,068,454	kWh		721,145,741	10,290,068,454	kWh		807,457,120	86,311,379	11.9686%
16											
17	Senior Care program	-	Bills	$ -	-	365,388	Bills	$ (10.00)		-	New Program
18	Total				-				-	-	New Program
19											
20	AMI Opt-Out	213,291	Days	$ 0.67	142,905	213,291	Days	$ 0.67	142,905	-	0.0000%
21	Total	213,291	Total Days		142,905		Total Days		142,905	-	0.0000%
22											
23	Total Base Revenue:				$ 920,603,768				$ 928,312,000	7,708,232	0.8373%
24											
25											
26	**Sun Select kWh are excluded from total kWh										
27											
28											
29											
30											
31											
32											
33											
34											
35											
36											
37											
38											
39											

Recap Schedules: E-13a