BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR BASE RATES INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

LAWRENCE J. VOGT

ON BEHALF OF TAMPA ELECTRIC COMPANY

PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

LAWRENCE J. VOGT

ON BEHALF OF TAMPA ELECTRIC COMPANY

Q. Please state your name, business address, occupation, and employer.

A. My name is Lawrence J. Vogt. My business address is 21093 Pineville Road, Long Beach, Mississippi 39560. I am the President and Principal Consultant of Vogtage Engineering Corporation.

Q. Mr. Vogt, please summarize your educational background and professional experience.

A. I am a graduate of the University of Louisville with Bachelor of Science and Master of Engineering degrees in Electrical Engineering. Over the last 45 years, I have held various positions including Distribution Engineer, Senior Industrial Marketing Engineer, and Rate Engineer at Public Service Indiana (now known as Duke Energy – Indiana) in Plainfield, IN; Senior Rate Design Engineer and Principal Engineer – Rates & Regulation at Southern Company Services

("SCS") in Atlanta, GA; Manager, Distribution Technologies Center at ABB Power T&D Company in Raleigh, NC; Lead Product Manager at Louisville Gas & Electric Company in Louisville, KY; and Manager, Pricing Planning and Implementation, and Director, Rates at Mississippi Power Company. In 2010, I established Vogtage Engineering Corporation. I have participated in numerous regulatory filings throughout my career in Alabama, Florida, Georgia, Indiana, Kentucky, and Mississippi and before the Federal Energy Regulatory Commission ("FERC"). This includes providing sponsored testimony and appearances as an expert witness in Commission hearings.

I have been active in a variety of industry functions throughout my career. I have conducted numerous industry lectures and workshops under the sponsorships of EUCI, the Electric League of Indiana, Inc., the University of South Alabama, and the Wisconsin Public Utility Institute. I have served as an Adjunct Professor in Pennsylvania State University's International Power Engineering Program (1989 – 2011). I served as a representative on the Rate & Regulatory Affairs Committee of the Edison Electric Institute, where I also served as Committee Chairman (2012 – 2014). I have also served as a Principal Instructor in the Committee-sponsored E-Forum Rate College and Electric

Rate Advanced Course. I also served as a representative on the Rates & Regulation Section of the Southeastern Electric Exchange. I am a Senior Life Member of the Institute of Electrical and Electronics Engineers, and I am a Member of the Association of Energy Engineers. I am a registered Professional Engineer in several states. In addition, I am the coauthor of several technical papers and reports as well as the textbook Electrical Energy Management (Lexington Books, 1977). I am also the author of the textbook Electricity Pricing: Engineering Principles and Methodologies (CRC Press, 2009) and of the "Engineering Principles of Electricity Pricing," Chapter 21 in Power Systems, 3rd ed. of The Electric Power Engineering Handbook, CRC Press, 2012. Additional details are found in my curriculum vitae attached as Appendix 1.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. No. I have not.

Q. Please state the purpose of your direct testimony.

A. The purpose of my direct testimony is to present and explain the cost-of-service study filed by Tampa Electric Company

("Tampa Electric" or "company") in this proceeding. Specifically, I present the following information:

1) The Jurisdictional Separation Study and resultant jurisdictional separation factors used for the 2020 historical period and the 2021 and 2022 projected periods that determine the portion of Tampa Electric's system rate base and operating expenses, which are subject to the jurisdiction of the Commission and form the basis for the company's proposed revenue requirement for the 2022 test year.

2) The 2022 projected period Retail Class Allocated Cost of Service and Rate of Return Studies that, for non-solar facilities, uses a 12 Coincident Peak ("CP") and 1/13th Average Demand ("AD") production capacity cost allocation methodology, which I will refer to as 12-CP & 1/13th AD. In addition, I will present the company's proposed cost allocation methodology for its utility-scale solar production facilities.

3) The company's proposed modifications to its Minimum Distribution System ("MDS") analysis.

4) The methods employed, facts considered, and principles upon which the Jurisdictional Separation Study and Cost-of-Service Study were prepared.

5) Conclusions regarding the adequacy of these studies and the reasonableness of the resulting costs being

used to support the rate design effort.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. I am sponsoring Exhibit No. LJV-1 consisting of one document, prepared under my direction and supervision:

Document No. 1	List Of Minimum Filing Requirements Schedules Sponsored Or Co-Sponsored By Lawrence J. Vogt

Q. Are Tampa Electric's Jurisdictional Separation Study and Cost-of-Service Study provided as part of the company's Minimum Filing Requirement ("MFR") schedules?

A. Yes, they are provided within the portion of the MFR schedules designated Section E, "Rate Schedules." I have provided the Jurisdictional Separation Study and the Cost-of-Service Study as well as work papers in separate bound volumes due to their voluminous size. Volume I contains the Jurisdictional Separation Study and the Cost-of-Service Study using the MFR-required 12-CP & 1/13th AD methodology with present and proposed rates.

Q. What are the company's primary goals for the proposed cost of service in this case?

A. There are four primary goals that are reflected in the cost of service of Tampa Electric in this case. The first goal is the modification of the retail rate classes designated in the cost-of-service study to accommodate the company's proposal to develop two new commercial and industrial rate classes. The second goal is the modification and refinement of the cost classification methodology applicable to distribution system facilities. The third goal is the use of the 12-CP and 1/13th AD production capacity allocation methodology for the non-solar generation capacity. The fourth goal is the implementation of a new allocation methodology for the company's solar-based production capacity.

JURISDICTIONAL SEPARATION STUDY

Q. What is a Jurisdictional Separation Study?

A. A Jurisdictional Separation Study is an allocation of costs between the company's wholesale and retail customers or jurisdictions. While all costs are allocated, the allocation of joint costs is the focal point of the study. Joint or common costs are costs that are incurred to serve multiple customers at the same time. A common example is a generating plant that provides power to the aggregate load requirements of all customers served by the company’s power system. The joint costs of the generating plant are recorded on the company’s books and records in total, and the Jurisdictional Separation Study allocates the joint costs between retail and wholesale customers. Only the costs associated with retail customers are applicable in this proceeding.

The Jurisdictional Separation Study allocates revenue, rate base, and operating expense items, whether jointly or specifically assigned to a single jurisdiction, to derive the company’s retail jurisdiction cost of service for the test period. Costs are first functionalized, then classified, and finally allocated between the wholesale and retail jurisdictions. These allocations utilize load and other factors that best represent each jurisdiction’s cost responsibility to achieve this purpose. A detailed description of how costs are functionalized, classified, and allocated is provided below. The overall methodology is the same in both the Jurisdictional Separation Study and the Retail Cost-of-Service Studies, which I will discuss later.

Q. Why is it necessary to prepare a Jurisdictional Separation Study for Tampa Electric?

A. Since early 1991, the company has provided wholesale power sales and transmission service to some wholesale power purchasers in Florida at rates that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Although the company operates in two regulatory jurisdictions, its investments, revenue, and expenses are maintained on a total company basis in accordance with the Uniform System of Accounts prescribed by the FERC and the Commission. The Jurisdictional Separation Study is designed to directly assign or allocate total system costs to each jurisdiction for reporting purposes.

Q. Is the Jurisdictional Separation Study provided in this proceeding consistent with Tampa Electric's previous Commission filings and industry practice?

A. Yes. The company provided a Jurisdictional Separation Study in its base rate proceeding in Docket No. 20080317-EI that led to an approved methodology by the Commission. That methodology has been used to produce separation factors for the annual projected surveillance reports, which are the same factors that have been used as separation factors for the 2020 and 2021 MFR schedules.

Q. What were the major steps followed in performing the Jurisdictional Separation Study?

A. There are several steps. First, the company’s accounting information provided by FERC account, shown in the MFR Schedules B, C and D, is adjusted for the 2022 test period. The accounts are then functionalized into production, transmission, distribution, and general functions. Next, they are classified into demand, energy, or customer groups. After classification, the groupings are allocated into the retail and wholesale jurisdictions using allocation factors. The allocation factors are predominantly based on demand data for the retail and wholesale jurisdictions during the time of the company’s projected system monthly peaks, although other factors are used that directly allocate certain costs to the specific jurisdiction for which the costs are incurred. In addition, other metrics such as energy sales and number of customers are used in the allocation process.

Q. Are any wholesale power sales customers included in the 2022 test year?

A. No. Currently and as forecasted for the 2022 test year, the company is not providing long-term firm requirements electric power service to any wholesale customers.

Q. Does Tampa Electric currently provide transmission service to other Open Access Transmission Tariff (“OATT”) customers?

A. Yes. Tampa Electric is providing long-term firm transmission service in the test year under the company’s OATT to Seminole Electric Cooperative, Inc. and Duke Energy Florida, LLC.

Q. Please summarize the results of the Jurisdictional Separation Study.

A. In 2022, the retail business represents the vast majority of the electric service provided by Tampa Electric. As the results show in Volume I, Jurisdictional Separation Study, the retail business is responsible for 100 percent of production and distribution plant and 93.32 percent of transmission plant.

COST OF SERVICE STUDY

Q. What is a Retail Class Allocated Cost-of-Service and Rate-of-Return Study ("Cost-of-Service Study" or "COSS")?

A. The retail Cost-of-Service Study is an extension of the Jurisdictional Separation Study. It starts with the retail portion of costs derived from the Jurisdictional Separation Study and further allocates and assigns these costs to individual retail rate classes. These rate classes represent relatively homogeneous groups of customers having similar service requirements and usage characteristics. Allocations of costs to each of these groups, like the Jurisdictional Separation Study, are based upon the results of a detailed cost analysis. The study provides class rates of return at present and proposed rates, class revenue surplus or deficiency from full cost of service, and functional unit cost information for use in rate design. Thus, the study serves as an important guide in determining the revenue requirement by rate class, as well as the specific charges for each rate schedule.

Q. What retail rate classes were used in the preparation of the Cost-of-Service Study?

A. Tampa Electric's current standard and time-of-day rate schedules are grouped under the major retail classifications of 1) Residential Service (RS), 2) General

Service - Non-Demand (GS), 3) General Service - Demand (GSD), 4) Interruptible Service (IS), and 5) Lighting Energy and Facilities. As discussed in Mr. Ashburn’s direct testimony, the Company proposes to restructure its demand rate services by creating two new rate schedules: a) General Service - Large Demand – Primary and b) General Service - Large Demand – Subtransmission. Qualifying customers currently served under the GSD rate would be moved to one of these new rate schedules based on their service voltages and demand levels. All of the customers currently served under the IS rate schedule would be moved to the appropriate GSLD rate. Thus, the retail rate classes used in the preparation of the 2022 test year cost-of-service study consist of 1) Residential Service (RS), 2) General Service - Non-Demand (GS), 3) General Service - Demand (GSD), 4) General Service - Large Demand Primary (GSLD-Primary), 5) General Service - Large Demand Primary (GSLD-Subtransmission), and 6) Lighting Energy and Facilities.

Q. Why are there two columns of information presented under the present and proposed rates in the Cost-of-Service Studies for lighting service: Lighting Energy and Lighting Facilities?

A. Dividing the lighting rate class into the two components, Lighting Energy (power production and delivery) and Lighting Facilities (fixtures and associated items), provides better unit cost information for designing the energy and facilities components of this rate class. The two components are distinct types of services and are not always provided as a bundled service by the company.

Q. After establishing the rate classes, what were the next steps in the Cost-of-Service Study process?

A. Similar to the Jurisdictional Separation Study, the development of a COSS consists of three major steps: 1) grouping all costs by function (cost functionalization), 2) classifying the functionalized costs by cost-causation service characteristics (cost classification), and 3) apportioning the resulting classified costs to the retail rate classes (cost allocation).

Q. How were Tampa Electric’s costs functionalized?

A. The company functionalized costs in accordance with the Uniform System of Accounts by dividing utility plant costs into the broad functions of production, transmission, distribution, and general. Operation and Maintenance

("O&M") costs and other expenses were functionalized in a comparable manner.

Q. How were Tampa Electric's costs classified after they were functionalized?

A. The company's power system operations are classified into three categories: demand, energy, and customer cost. Demand cost is a function of the capacity of plant, which in turn depends on the maximum kW for power demanded by customers. Demand cost occurs in each of the production, transmission, and distribution levels of the system. Energy cost occurs in the production level, and it is a function of the volume of kWh consumed by customers over time. Customer costs, however, are independent of customers' kW and kWh usage. Many of these costs vary with the number of customers on the system. This generally refers to the basic costs incurred by the utility to attach a customer to the distribution system, which includes metering, service lines, a portion of the system known as the Minimum Distribution System ("MDS"), along with customer billing and certain administrative costs.

Subsequently, Tampa Electric's cost of service is measured by these same three cost categories: demand, energy, and customer. The three categories are appropriately called cost causations. The assignment of costs to these cost-causation categories in the COSS is called classification.

Q. Are all of the company’s production plant facilities classified as demand–related in the cost-of-service studies?

A. No. For purposes of jurisdictional separation, all production plant facilities are classified as demand related consistent with prior jurisdictional separation practices. However, there are portions of two production facilities that are classified as energy-related for purposes of allocating the Commission jurisdictional component of these facilities on an energy basis. These facilities consist of the gasifier train equipment (“gasifier”) for Polk Unit 1 and the flue gas desulfurization, or scrubber, portion of the environmental equipment for Big Bend Unit 4.

Polk Unit 1 is an Integrated Gasified Combined Cycle (“IGCC”) plant which has two main sections – the power block, which produces the electric power through gas turbines and heat recovery steam generators, and the gasifier, which converts coal as the feedstock into a combustible gas, which then becomes the fuel used in the power block. Thus, the gasifier performs a fuel conversion function that is completely associated with the provision of fuel to the unit and not the supply of capacity. The classification of the gasifier as energy-related was applied in Tampa Electric's last three cost of service studies.

The classification of the Big Bend Unit 4 scrubber as energy-related was applied in the company's last four cost of service studies. This treatment remains appropriate because the main purpose of the plant investment is related to energy output. Since the decision to classify the scrubber investment as energy-related, additional scrubber and Selective Catalytic Reduction ("SCR") investments made by the company have been recovered through the Environmental Cost Recovery Clause ("ECRC") where they have been classified and allocated on an energy basis.

Q. How are costs classified to the customer function?

A. Costs classified to the customer function are those generally independent of kW and kWh consumption. They have traditionally included the costs of service lines, meters, meter reading, billing, and customer information. In addition, the company has employed a costing methodology in this case that is described in the industry as the MDS method. This method determines the minimum size and respective cost of distribution transformers, poles, and conductors that would be required to connect customers to the company's power grid and provide an appropriate utilization voltage. This minimum cost is also classified as customer-related, and the remaining cost of these facilities is then classified as capacity or demand related. The methodology is described in the NARUC Cost Allocation Manual and has recently been accepted by the Commission in the settlement of rate and cost of service matters in the company's 2013 retail rate case.

Q. Please describe what is meant by a Minimum Distribution System?

A. The MDS is that portion of the total costs of facilities that make up the primary voltage lines, the line transformers, and the secondary voltage lines, which is independent of customers' load requirements. An MDS study separates the costs of these distribution facilities into their respective demand-related cost components and customer-related cost components on the basis of cost causation.

MDS represents the readiness to serve a customer, not the capacity needed to meet a customer’s peak demand requirements. MDS is only about providing an appropriate utilization voltage at the point at which a customer connects to the distribution system, and costs are incurred to provide a customer with such access. The readiness to serve costs is independent of how much electricity a customer consumes; thus, MDS costs are classified as customer-related cost components. MDS does not represent the costs of capacity necessary to meet a customer’s peak load requirements. That portion of the total costs of facilities that make up the primary voltage lines, the line transformers, and the secondary voltage lines that provide capacity to meet customers’ peak load requirements is classified as a demand-related cost component.

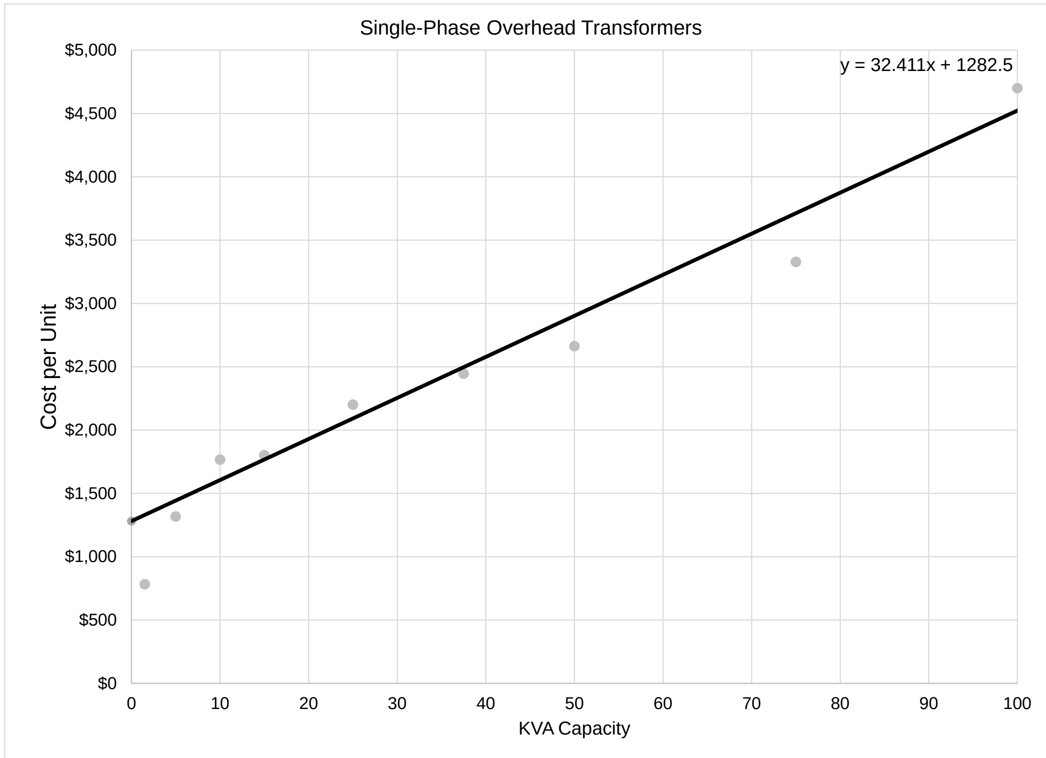
Q. How is an MDS study performed?

A. Quantifying the costs of MDS is accomplished by evaluating the cost causation aspects of all distribution system equipment and facilities, including the primary and secondary lines, line transformers, and other distribution line equipment. This approach requires an understanding of the functional application of each distribution item. In so doing, some items are found to be related directly to peak load requirements (100% demand related), some items are found to be independent of peak load requirements (100 percent customer related), and other items are found to be functionally associated with both readiness to serve and capacity.

The costs of items having attributes of both customer-related and demand-related functions must be analyzed in order to separate the total item cost into these two cost components. These items include overhead conductors and poles, underground conductors and conduit, and overhead and underground line transformers. They all provide both a readiness to serve function and a capacity function.

To accomplish this cost separation, the company applies a zero-intercept cost analysis for each of these distribution items. The zero-intercept method is a linear regression analysis that relates a distribution item's unit costs (dependent variable) to its associated capacity values (independent variable). An example of the regression analysis results is illustrated below for single-phase overhead line transformers.

The data plots shown in the chart represent the current unit costs of transformers having standard size capacity ratings, e.g., 10, 15, 25, 37.5, 50, 75, and 100 kVA. The regression analysis was conducted using current unit costs because average unit costs calculated from the company's embedded plant account data represent a mix of transformers having a variety of input and output voltages. Some of these transformers have higher voltages, compared to the basic 120/240 volt used for small single-phase customers, and the higher voltage transformers generally have a higher unit cost. To refine the analysis to basic single-phase transformers, the company's distribution mapping system was queried to determine the number of in-service overhead single-phase transformers for each kVA size by voltage ratings. In addition, the linear regression formula includes weights (i.e., the number of transformers for each kVA size) since the count of transformers for each size is not a uniform distribution.



The resulting regression line intersects the unit cost y-axis where the value of transformer capacity is equal to zero, thus defining the per unit customer component cost, which in this example is $1,282.50. This zero-intercept value is multiplied by the total number of single-phase overhead transformers to determine that amount of the total cost of single-phase overhead transformers that is classified as customer related. The difference between the total cost of the transformers and the customer-related cost amount represents the demand-related transformer cost amount.

Since the analysis was based on current unit costs, the resulting total customer cost and total demand cost are represented as percentages, which are then applied to the embedded plant account total for overhead transformers to determine the embedded customer-related and demand-related cost components to be used in the COSS.

Separate regression analyses were also conducted for underground pad mounted transformers and for primary and secondary overhead conductors, underground conductors, and distribution poles to separate the total costs of these items into their respective customer and demand cost components.

Q. Aside from the MDS-related equipment and facilities that you discussed, how are the other distribution system equipment and facilities classified?

A. Distribution property that is classified as 100% demand-related components include voltage regulators and capacitors. This equipment is installed on the primary voltage lines and is utilized to maintain circuit voltages within an acceptable operating range during heavy loading conditions. If there was no load current flowing on the energized system, line voltage would not sag, and voltage regulation equipment would not be required. Thus, these devices are classified as demand related.

Distribution property that is independent of load and is thus classified as 100 percent customer-related components include reclosers, sectionalizers, and fused cutouts. This equipment is installed on the primary voltage lines and function together to provide distribution system protection under fault (short circuit) conditions. These devices work in a coordinated fashion to isolate a fault location and maintain a voltage connection to as many customers as possible during the fault event. Without their intended intervention during a fault, line conductors and equipment would be damaged from the fault current flows that occur and many, if not all, customers on the affected circuit could experience a major power outage. The protection equipment functions the same with or without load connected to the energized circuit because it responds to the severe overcurrent situation caused by a fault. Thus, these devices are classified as customer related.

In addition, lightning arresters are installed on the primary lines to abate damaging overvoltage conditions that occur during electrical storms. These lightning arresters function the same with or without load connected to the circuit. Thus, these devices are classified as customer related.

While cutouts and arresters are utilized for line protection, they are also applied to provide protection from overcurrent and overvoltage conditions for specific equipment, e.g., each overhead transformer. Cutouts and arresters used for this purpose are classified in the same manner as the equipment they protect was classified.

Q. Please summarize the resultant classifications of distribution facilities that you have derived under the refined MDS concept

A. The refined MDS study results are summarized by voltage level and cost component.

		Cost Component	
FERC Account	**Voltage Level**	**Customer**	**Demand**
364 Poles	Secondary	68%	32%
	Primary	60%	40%
365 OH Lines	Secondary	44%	56%
	Primary	49%	51%
366/367 UG Lines	Secondary	16%	84%
	Primary	47%	53%

368 Transformers	Secondary	58%	42%
	Primary	17%	83%

Supporting workpapers for the MDS analysis are provided in MFR Schedule E – Rate Schedules, Class Cost-of-Service Studies, Volume II.

Q. How were the MDS study results incorporated into the cost-of-service study?

A. The MDS customer and demand cost component percentages were applied to separate the costs of the plant in service for the primary and secondary voltage distribution FERC Accounts, including FERC 364, FERC 365, FERC 366, FERC 367, and FERC 368. Then an assessment was made of the subsequent Derivation of Unit Cost report that is shown on page 28 of the Cost-of-Service Study. Specifically, the monthly amounts of the customer-related costs for each rate class were evaluated in comparison to the comparable results of the cost-of-service study approved in the 2013 rate case filing. The customer-related cost component consists of MDS, meters, meter reading, billing, and customer services. The combined increases of these cost components moved the total customer cost amount materially higher than the total customer cost determined in the previous rate case filing.

While some state jurisdictions utilize the cost-of-service study as a general reference for rate design purposes, the establishment of rate components in Florida is more directly coupled with cost-of-service study results. Subsequently, the company proposes gradualism in implementation of the refined MDS analysis while consenting the full cost amounts for meters, meter reading, billing, and customer service, in order to mitigate the otherwise higher rate impact due to a full cost-based ratemaking approach.

Thus, in this filing, the company further proposes to incorporate one half of the MDS customer cost percentage results in this filing. While this proposal would then shift one half of the quantified customer-related costs to the demand-related cost component for ratemaking purposes, the refined MDS analysis stands on its own merits for full cost causation acknowledgement.

Q. After costs were functionalized and classified, how were they allocated?

A. After determining the functionalization and classification of costs based upon causation principles, the methodologies for cost apportionment to classes were determined. The resulting methodologies produce allocation factors, which are then used to apportion the demand, energy, and customer cost responsibilities to the rate classes. The derivation of the allocation factors used in the 2022 Cost of Service Study is shown in MFR Schedule E-10.

Q. What are the principal considerations when allocating demand costs?

A. The principal considerations in allocating demand costs include 1) customer demand usage characteristics and their related responsibility for system coincident and non-coincident peaks, 2) the design and configuration of production, transmission, and distribution facilities, and 3) unique customer service or reliability requirements and system operating data. These considerations provide guidance in determining what components should be used to derive the demand allocation factors for each of the functional levels of the power system. CP demands, non-coincident peak demands ("NCP"), customer peak (maximum) demands, and percentage of energy have been used to best represent those considerations.

Q. Please explain CP, NCP, and customer peak demand.

A. CP demand reflects the contribution to the total system monthly peak demand for each of the rate classes. For example, at the hour of the system peak in a particular month, the CP demand for the residential class would be that class’s proportion of that hour’s system peak demand.

NCP demand reflects the monthly peak demand of a rate class on its own, regardless of when the system peak occurs. For example, while the system may peak in the late afternoon, a class may peak during a nighttime hour. The class NCP would then be its demand during that nighttime hour.

For each rate class, the customer peak demand is the aggregation of all individual customers’ monthly maximum demands, regardless of when they occur.

Each of these different measures of demand capture the unique load diversity characteristics of customers’ usage throughout the power system. To produce a cost-causation based allocation of the cost elements at each functional level of the system, these different measurements of demand are applied objectively in accordance with the load diversity characteristics exhibited at each of those levels. The CP demand reflects a high load diversity, which is prevalent at the generators and the transmission voltage portion of the system. The NCP demand reflects a medium load diversity, which is prevalent at the primary distribution voltage level. The customer peak demand reflects a low load diversity, which is prevalent at the secondary distribution voltage level.

Q. Please describe the company's proposed cost allocation methodology for its non-solar production facilities.

A. For its non-solar production facilities, the company has proposed to allocate these costs to the retail rate classes by utilizing the 12-CP and 1/13th AD method. With this method, 12/13ths of the production cost is allocated by means of the 12-CP demands while the remaining 1/13th of the production cost is allocated based on the average demand. This method was utilized in the settlement of the 2013 rate case and thus is proposed in this proceeding.

Q. Please describe the company's proposed cost allocation methodology for its utility-scale solar production facilities.

A. Prior to this filing, the cost of the company's solar facilities was embedded with the costs of all of its conventional generation resources. Thus, the cost of the solar facilities was allocated to the rate classes in accord with the non-solar resources, i.e., using the 12-CP and 1/13th AD allocation. With the company's expansion of PV as a material utility-scale resource, the company believes that allocation of solar generation should be based on its unique characteristics. The company's current and planned renewable generation resources portfolio includes utility-scale, single-axis tracking PV and battery storage. These methods provide an improvement in the generation output characteristics of an otherwise static PV resource.

The daily generation output of a fixed-tilt solar PV system has a shape very much like a normal distribution curve between sunrise and sunset and which ramps up to its peak kW output at noontime and then begins ramping down shortly thereafter. The daily energy output can be increased by using a single-axis tracking system that allows the solar panels to rotate from an east facing position each morning to a west facing position each evening as the sun moves from horizon to horizon. Compared to a fixed-tilt PV panel, the annual energy output of a single-axis tracking panel may be increased by as much as 27 percent.[1] The resulting shape of the daily generation output approaches that of a

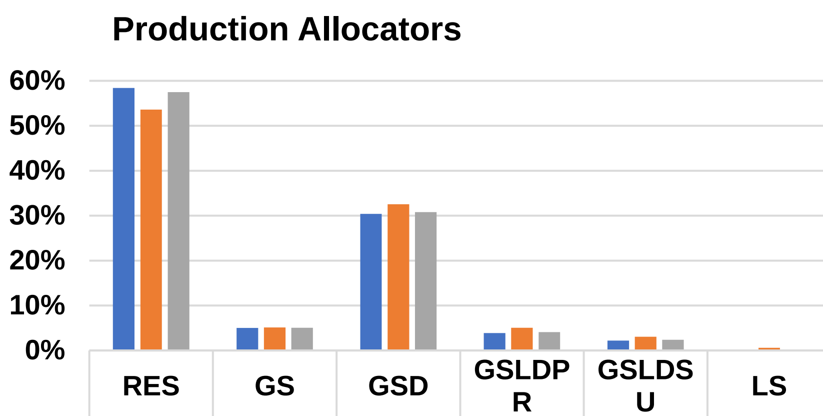
[1] "Utility-Scale Solar Photovoltaic Power Plants: A Project Developer's Guide'" International Finance Corporation, Washington, D.C., 2015, p. 34.

trapezoid with steep side legs. Thus, the panel's peak kW output period is reached much earlier than noon and extends to well past noon. This allows the solar panel to contribute more effectively to meeting late afternoon summer loads driven by air conditioning.

"Coupling" storage batteries with PV systems has a benefit of mitigating some of the intermittency aspect of solar resources. Batteries provide a means for storing electricity from PV units as a reserve for use at times when the PV output is intermittent or even zero. For example, charged batteries could help meet the energy requirements of a pre-dawn heating load.

The company's renewable resource expansion strategy yields both peak capacity and energy output merits. Thus, a cost allocator which encompasses both demand and energy metrics is appropriate. The company proposes to base its PV resource cost allocator on a 50 percent/50 percent weight with respect to demand and energy. The demand portion of the allocation is based on 25 percent of the average of the ten highest monthly CPs in the summer plus 25 percent of the average of the ten highest monthly CPs in the winter. The energy portion of the allocation is based on 50 percent of the annual daylight kWh.

The chart below compares the rate class allocation factors for the 12-CP and 1/13th methodology and the proposed demand and energy-weighted solar allocation methodology. The chart also illustrates the resulting total production allocation by rate class.



	RES	GS	GSD	GSLDPR	GSLDSU	LS
12-CP & 1/13th AD	58.4%	5.0%	30.4%	3.9%	2.2%	0.1%
25% Average Summer CPs + 25% Average Winter CPs + 50% Daylight Energy	53.6%	5.1%	32.5%	5.1%	3.1%	0.6%
Total	57.5%	5.0%	30.8%	4.1%	2.4%	0.2%

Q. Please explain the treatment of demand allocated transmission and distribution costs in the Cost-of-Service Study.

A. The transmission demand-classified costs are allocated on a 12-CP basis while distribution demand-classified costs are allocated on a mixture of rate class NCPs and customer maximum demands. This is the same allocation methodology as was adopted and relied on in the company’s base rate proceeding in Docket No. 20080317-EI.

SUMMARY

Q. Please provide a summary of the company’s proposed Cost-of-Service Studies in this proceeding.

A. In line with the cost-of-service study goals stated previously, the company successfully modified the model to create two new commercial and industrial rate schedule classes for larger customers that are served at primary and subtransmission voltages, which were then incorporated in the retail cost allocation process.

The company refined its minimum distribution system methodology to analyze distribution costs at a comprehensive level of detail. The results were successfully employed in the cost-of-service study to classify the costs of the primary and secondary distribution voltage levels.

The company employed the following cost allocation factors to apportion the functional costs of capacity to the customer rate classes:

Production – Non-Solar	12-CP and 1/13th AD
Production – Solar	25 percent of the 10 highest Summer CPs plus 25 percent of the 10 highest Winter CPs plus 50 percent of Daylight Energy
Transmission	12-CP
Substations	Class NCPs
Primary Distribution	Class NCPs
Secondary Distribution	Customer Maximum Demands

Prior to this filing, solar production was allocated along with all other production.

The modifications made to the company's cost-of-service methodologies and applications, which have been employed in this filing, strive to capture and enhance cost-causation principles to the benefit of electric service customers. The cost-of-service study results are fair and equitable, and it serves as a practical resource in support of the rate design process.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix 1

Lawrence J. Vogt
President and Principal Consultant
Vogtage Engineering Corporation

Summary Of Utility Industry Experience

- B.S. & M.Eng Degrees in EE
- Licensed Professional Engineer
- Expert Witness
- Published Author
- Professional Instructor
- Project Manager
- Business Unit Manager
- Utility Consultant

WORK EXPERIENCE

Rates Engineering

Pricing Strategy – Development and implementation of long-term plans for retail tariff restructuring and rate structure modifications based on projected industry contingencies.

Cost-of-Service Studies – Design and construction of a comprehensive Excel-based electric cost-of-service model; development of a GIS-based minimum distribution system methodology for customer–demand cost classification; design of a comprehensive system electric loss study methodology for use in energy and demand allocation factor development; development of rate schedule functional cost components for use in rate design.

Rate Design Studies – Development of coincidence factor–load factor curves using interval data and hours use of demand based bill frequency distributions for intra-rate electric cost allocation and production of rate schedule cost curves for supporting demand-based rate structures; development of alternative rate structures for all customer classes, including block energy, demand, hours use of demand, and time of use; development of outdoor lighting and facilities lease rates; development of special electric rates, including economic development, generation standby, purchase of excess customer generation energy, and interruptible rates; development of various cost recovery clauses; administration of rates and associated policies.

Rate Analysis – Development of mathematical and graphical techniques for evaluation of electric rates and rate relationships; development of unique rate analysis methodologies, e.g., contour-based differential rate charts; conceptual outline of a rate design and analysis tool (*RateManager*, coded and commercialized by Good¢ents Solutions).

Electric Service Revenue Forecasting – Development of historical and projected billing determinant databases using average rate and ogive forecasting methodologies for residential and small commercial customer classes and a discrete bill forecasting methodology for large commercial and industrial customers; development of projected customer rate

Regulatory Support – Preparation of retail and wholesale regulatory filing documents, including testimony, exhibits, and responses to interrogatories; appearance as an expert witness in regulatory docket proceedings; participation in special regulatory meetings, such as collaborative interest groups; design and implementation of formulary performance-based ratemaking methods. Development and presentation of instructional courses in ratemaking principles and methodologies.

Power Distribution Engineering

Distribution Planning – Development of load-bearing land use databases calibrated to substation peak loads and service areas; spatial allocation of projected customer class loads; optimization of substation capacity sizing and siting; forecasting and outage contingency analyses.

Integrated Resource Planning – Development of DSM-based customer class load models; spatial analysis of DSM impacts on T&D loads and substation capacity expansion using distribution planning software.

Distribution Design and Analysis – Routing and specification of primary feeder lines and equipment; specification of electric service facilities; feeder protection coordination studies; capacitor sizing and siting studies.

Distribution System Restoration – Field engineering support of distribution system restoration efforts due to tornados and hurricanes.

Marketing

Industrial Marketing – Engineering assistance to commercial and industrial customers for new load additions, demand and energy management project evaluations, power factor correction projects, electric service invoices, and rate schedule selection; development and presentation of customer education programs.

Products and Services Marketing – Development of optional products and services proposals for large C&I customers, including distribution engineering, line construction, and maintenance services; coal procurement; development of a standard service criterion.

Business Unit Management

Electric Rates Function – Management of a team of engineers, accountants, economists, and computer scientists responsible for:

- Development of jurisdictional and customer and rate class cost-of-service studies.
- Design of electric rates for all categories of retail and wholesale electric services.
- Application and governance of the electric tariff.

Power Distribution Function – Management of a team of engineers and geographers responsible for:

- Digitizing distribution electric circuit maps and construction of geographical load databases for use in distribution system planning and analysis.
- Production of spatial electric load forecasts.
- Development of least-cost distribution system expansion plans, including the effects of demand-side management and energy efficiency programs.

COMPANY AND POSITION HISTORY

Vogtage Engineering Corporation		**July 2010 – Present**
Long Beach, Mississippi		
Position:	President and Principal Consultant	
Mississippi Power company, A Southern company		**April 1997 – May 2018**
Gulfport, Mississippi		
Positions:	Director, Rates	August 2014 – May 2018
	Manager, Rates	August 2005 – July 2014
	Manager, Pricing Planning & Implementation	June 1998 – July 2005
	Principal Rate Research Analyst	March 1997 – June 1998
Louisville Gas and Electric company		**September 1994 – March 1997**
Louisville, Kentucky		
Positions:	Lead Product Manager	November 1996 – March 1997
	Rates and Regulatory Coordinator	September 1994 – October 1996
ABB Power T&D company		**August 1989 - September 1994**

Pittsburgh, Pennsylvania and Raleigh, North Carolina

Positions:	Manager, Distribution Technologies Center	January 1994 - September 1994
	Manager, Consulting Studies	June 1992 - December 1993
	Consulting Engineer	August 1989 - May 1992

Southern company Services, Inc., A Southern company — **March 1980 – July 1989**

Atlanta, Georgia

Positions:	Principal Engineer – Rates & Regulation	June 1987 – July 1989
	Assistant to the Assistant Vice President	May 1984 – May 1987
	Senior Rate Design Engineer	April 1983 – April 1984
	Rate Design Engineer	March 1980 – March 1983

Public Service company of Indiana, Inc. — **May 1976 – February 1980**

(Now known as Duke Energy – Indiana)

Plainfield, Indiana

Positions:	Rate Engineer	February 1979 – February 1980
	Senior Industrial Marketing Engineer	May 1977 – January 1979
	Engineer	May 1976 – April 1977
	Student Engineer (Co-op and Part Time)	Prior to May 1976

EDUCATION

University of Louisville, Louisville, Kentucky

Bachelor of Science (Electrical Engineering)	May 1975	
Master of Engineering (Electrical Engineering)	May 1976	Thesis: "Electrical Energy Management"

PROFESSIONAL AFFILIATIONS

Institute of Electrical and Electronics Engineers — Senior Member, ID: 07062771 (Since 1974)

- Power Engineering Society: Customer Products and Services Subcommittee; Power Systems Planning and Implementation Subcommittee
- Industry Applications Society

Association of Energy Engineers — Member, ID: 01969 (Since 1978)

Edison Electric Institute — Member, Rate Committee (2005 - 2018)

- Committee Chairman, 2012 - 2014
- Committee Vice Chairman, 2010 - 2012

Southeastern Electric Exchange — Member, Rates & Regulation Section (2010 - 2018)

Registered Professional Engineer:

Alabama, ID: 13650-PE, December 1981	Georgia, ID: PE012852, April 1981
Indiana, ID: PE60018668, January 1980	Mississippi, ID: 08429, September 1981
Vogtage Engineering Corporate License:	Mississippi Certificate of Authority: E-2258

REGULATORY FILINGS AND TESTIMONY

Georgia Public Service Commission

Testimony and appearances on behalf of Georgia Power company.

- Docket No. 42516: 2019 Georgia Power company Retail Rate Case; prefiled testimony on retail cost-of-service study; public hearings held; order issued.

Mississippi Public Service Commission

Testimony and appearances on behalf of Mississippi Power company.

- Docket 2017-AD-112, 2017: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project; prefiled testimony on test period rate revenues; public hearing held; order issued.
- Docket 2016-UA-230, 2016: Jurisdictional Cost-of-Service Study as of December 31, 2015; prefiled testimony on cost assignment methodologies; order issued without a hearing.
- Docket 2015-UN-80, 2015: A Change in Rates Related to the Kemper County IGCC Project; prefiled testimony on cost recovery methodology and rate schedule revisions; public hearing held; order issued.
- Docket 2014-UN-10, 2014: Establishment of an Energy Efficiency Quick Start Plan and Cost Recovery Rate; prefiled testimony on cost recovery methodology; order issued without a hearing.
- Docket 2013-UN-14, 2013: A Change in Rates Related to the Kemper County IGCC Project; prefiled testimony on cost recovery methodology and rate schedule revisions; public hearing held; order issued.
- Docket 2011-UN-0135, 2011: Establishment of a Certificated New Plant Rate Schedule; prefiled testimony on cost recovery methodology and rate schedule revisions; public hearing held; order issued.
- Docket 2011-AD-2, 2011: Investigation of the Development and Implementation of Net Metering Programs and Standards; prefiled comments on specific issues that should be addressed in a possible rule; public hearing held; order issued.
- Docket 1992-UN-0059, 2011: Environmental Compliance Overview Plan; prefiled testimony on modification of the cost recovery mechanism and change in billing factors; public hearing held: order issued.
- Docket 2010-AD-2, 2010: Investigation of the Development and Implementation of Energy Efficiency Programs and Standards; prefiled comments on decoupling and lost sales, incentives, and program cost recovery; collaborative meetings; prefiled testimony on cost recovery; rulemaking order issued without a hearing.
- Docket 1992-UN-0059, 2010: Environmental Compliance Overview Plan; prefiled testimony on change in billing factors; public hearing held: order issued.
- Docket 1992-UN-0059, 2009: Environmental Compliance Overview Plan; prefiled testimony on change in billing factors; public hearing held.
- Docket 2008-AD-0477, 2008: Energy Independence and Security Act of 2007; prefiled comments on “Rate Design Modifications to Promote Energy Efficiency Investments”; public hearing held: order issued.
- Docket 2007-UN-0398. 2007: Establishment of a Formulary Lighting Charge Rate Schedule; order issued without a hearing.
- Docket 2007-UN-0395. 2007: Revision of the Cogeneration and Small Power Purchase Rate Schedule; order issued without a hearing.
- Docket 2007-AD-0201, 2007: Energy Policy Act of 2005 -- Proposed PURPA Standards; prefiled comments on "Net Metering;" public hearing held: order issued.
- Docket 2006-UN-0511, 2006: Establishment of a System Restoration Rider Schedule; prefiled testimony on cost recovery methodology; order issued without a hearing.
- Docket 2005-UA-0555, 2006: Hurricane Katrina System Restoration Cost Recovery; pre-filed testimony on cost recovery methodology; public hearing held: order issued.
- Docket 2006-AD-0362, 2006: Energy Policy Act of 2005 -- Proposed PURPA Standards; prefiled comments on "Smart Metering and Interconnection"; public hearing held: order issued.

- Docket 2003-UN-0898, 2005: Performance Evaluation Plan General Increase in Rates; prefiled testimony on rate schedule revisions; public hearing held: order issued.

Kentucky Public Service Commission
Filings on behalf of Louisville Gas & Electric company.

- Case 95-239, 1995: Small Power Production and Cogeneration Purchase Schedule; filed revised schedule SPPC-II; order issued without a hearing.

- Case 95-276, 1995: Establishment of an Excess Facilities Rider; filed new schedule; order issued without a hearing.

- Case 93-150, 1995 and 1996: Quarterly filing of exhibits and rates for Demand-Side Management Cost Recovery Mechanism; orders issued without a hearing.

- Case 73-146, 1995 and 1996: Annual filing of exhibit and rate for Differential Underground Charge for New Residential Subdivisions; orders issued without a hearing.

Indiana Utility Regulatory Commission
Testimony and appearances on behalf of Public Service Indiana.

- Cause No. 35755, 1979: Joint Petition of Public Service company of Indiana, Inc. and United Rural Electric Membership Corporation; prefiled testimony addressing the rate impacts associated with the exchange of properties and customers; public hearing held; order issued.

- Cause No. 35756, 1979: Joint Petition of Public Service company of Indiana, Inc. and Morgan County Rural Electric Membership Corporation; prefiled testimony addressing the rate impacts associated with the exchange of properties and customers; public hearing held; order issued.

- Cause No. 35954, 1979: Joint Petition of Public Service company of Indiana, Inc. and Parke County Rural Electric Membership Corporation; prefiled testimony addressing the rate impacts associated with the exchange of properties and customers; public hearing held; order issued.

Federal Energy Regulatory Commission
Testimony on behalf of Mississippi Power company.

- Docket ER11-1871, 2010: Wholesale Rate Case
  Prefiled testimony on rate design; case settled and order issued without a hearing.

- Docket ER08-1467, 2008: Wholesale Rate Case
  Prefiled testimony on rate design; case settled and order issued without a hearing.

PUBLICATIONS

Books

Lawrence J. Vogt, "Engineering Principles of Electricity Pricing," Chapter 21 in *Power Systems*, 3rd ed. Edited by Leonard L. Grigsby, CRC Press, 2012.

Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies*, CRC Press, 2009.

Lawrence J. Vogt and David A. Conner, *Electrical Energy Management*, Lexington Books, 1977.

Reports and Papers

H. L. Willis, L. J. Vogt, R. G. Huff, and W. R. Pettyjohn, "DSM: Transmission and Distribution Impacts, Volume 1: Analysis Framework and Test Case," EPRI Final Report CU-6924, Vol. 1, August 1990.

H. L. Willis, L. J. Vogt, H. N. Tram, and J. M. Fredley, "DSM: Transmission and Distribution Impacts, Volume 2: Application on Spatial Frequency Analysis," EPRI Final Report CU-6924, Vol. 2, August 1990.

J. Flory, J. Peters, L. Vogt, K. Keating, B. Hopkins, and N. R. Friedman, "Evaluating DSM: Can An Engineer Count On It?" IEEE Transactions on Power Systems, Vol. 9, No. 4, pp. 1752 – 1758, February 1994.

Lawrence J. Vogt and H. Lee Willis, "Optimizing the Power System Impacts of Demand-Side Management," IEE Conference Publication No. 373, CIRED 12th International Conference on Electricity Distribution, Birmingham, UK, pp. 6.4.1 – 6.4.5, May 1993.

Lawrence J. Vogt, H. Lee Willis, and Lynn C. Ribar, "DSM and the T&D System: A Complicated Interaction," EPRI CU-7394; Proceedings of the 5th National Demand-Side Management Conference, Boston, MA, pp. 305 - 309, August 1991.

Lawrence J. Vogt, H. Lee Willis, and Michael J. Buri, "Distribution Planning and DSM Assessment Using Satellite Imagery and Pattern Recognition," Proceedings of the Pennsylvania Electric Association's System Planning Committee Meeting, Wilkes-Barre, PA; May 1991.

Timothy S. Yau, William M. Smith, R. Gary Huff, Lawrence J. Vogt, and H. Lee Willis, "Demand-Side Management Impact on the Transmission and Distribution System," IEEE Transactions on Power Systems, Vol. 5, No. 2, pp. 506 – 512, May 1990.

Lawrence J. Vogt, "History of the AEIC Load Research Committee: 1944 – 1985, June 1985.

INDUSTRY PRESENTATIONS

Institute of Electrical and Electronics Engineers

"Engineering in Customer Service Planning – Utility Products and Services," IEEE Power Engineering Society Meeting, Seattle, WA; July 2000.

"Evaluating DSM: Can an Engineer Count On It? – Verifying DSM Load Reduction: T&D Engineering Perspectives," IEEE Power Engineering Society Meeting, Seattle, WA; July 1992.

Edison Electric Institute

"Formulary Methodology for Pricing Lighting Facilities," EEI Rate and Regulatory Affairs Committee Meeting, Chicago, IL; September 2013.

"Minimum Distribution System: Concepts and Applications," EEI Rate and Regulatory Affairs Committee Meeting, Louisville, KY; March 2013.

"Trends in Riders: What's Out There?" EEI Rate and Regulatory Affairs Committee Meeting, Clearwater, FL; March 2012.

"Transition to Forecast Test Years: Mississippi Power Perspective" and "Performance-Based Ratemaking for New Generation," EEI Rate and Regulatory Affairs Committee Meeting, Alexandria, VA; September 2011.

"Mississippi Power's Retail Pricing Mechanisms," EEI Rate and Regulatory Affairs Committee Meeting, Jersey City, NJ; March 2010.

"Rate Design Transition at Mississippi Power," EEI Rate and Regulatory Affairs Committee Meeting, New Orleans, LA; March 2009.

"Ratemaking With Bary Curves," EEI Rate Analysts Meeting, Louisville, KY; April 2008.

"Ratemaking With Bary Curves," EEI Rate and Regulatory Affairs Committee Meeting, San Francisco, CA; September 2007.

"Hurricane Katrina: Impacts and Cost Recovery Issues" and "Mississippi Power's Performance Evaluation Plan," EEI Rate and Regulatory Affairs Committee Meeting, Savannah, GA; March 2006.

Southeastern Electric Exchange

"Impacts of PV on Distribution Systems," S.E.E. Rates and Regulation Section Meeting, Lexington, KY; April 2019.

"Demand and Energy Loss Factors Used in the Cost-of-Service Study," S.E.E. Rates and Regulation Section Meeting, Charlotte, NC; April 2018.

"Model-Based Approach to Rate Design: Exploring Rate Relationships," S.E.E. Rates and Regulation Section Meeting, Williamsburg, VA; April 2016.

"Cost-Based Rate Design: A Deeper Dive," S.E.E. Rates and Regulation Section Meeting, Mobile, AL, April 2015.

"Straight Fixed–Variable Rate Design," S.E.E. Rates and Regulation Section Meeting, Atlanta, GA; October 2014.

"Update on Kemper County IGCC Energy Facility," S.E.E. Rates and Regulation Section Meeting, Charleston, SC; October 2013.

"Minimum Distribution System: Concepts and Applications," S.E.E. Rates and Regulation Section Meeting, Savannah, GA; October 2012.

"Formulary Lighting Pricing," S.E.E. Rates and Regulation Section Meeting, New Orleans, LA; November 2011.

"Mississippi Power's Revenue Neutral Adjustment Clause," S.E.E. Rates and Regulation Section Meeting, Atlanta, GA; May 2011.

"Fundamentals of Rate Design Workshop," S.E.E., Rates and Regulation Section Meeting, St. Petersburg, FL; May 8, 2003.

"Cost Analysis and Rate Design: Outdoor Lighting," S.E.E. Rates and Regulation Section Meeting, Richmond, VA; October 1981.

EUCI Conferences

"Experiences With Formulary Ratemaking," EUCI's 10th Annual Electricity Pricing Conference, New Orleans, LA; September, 2012.

"Mississippi Power's Success: Hurricane Katrina Impacts and Response" and "Hurricane Katrina: Cost Recovery Issues," EUCI's Disaster Management and Cost Recovery for Utilities and Energy Companies Conference, New Orleans, LA; June 2006.

"Planning DSM to Optimize T&D Benefits," EUCI's Integrated Resource Planning Conference, Denver, CO; March 1993; Co-presenter – Lee Willis

Other Industry Conferences

"Employing a Minimum Distribution System Methodology for the Cost-of-Service Study," Marcus Evans Electric Utility Ratemaking Conference, Atlanta, GA; July 2013.

"Bridging the Gap Between Cost of Service and Rate Design Structure," The Prime Group's Electric Cooperative Rate Conference, Louisville, KY; September 2007.

"Developing Pricing Structures to Market Reliability-Based Service Options" (pre-conference workshop), The Center for Business Intelligence's "Electric Distribution Reliability" Conference, Houston, TX; February 2001; Co instructor – Arlan W. Chenault.

"Spatially Differentiated Pricing," INFOCAST's "Pricing Strategies for the Competitive Era" Seminar, Chicago, IL; January 1997.

"DSM and the T&D System: A Complicated Interaction," The 5th National Demand-Side Management Conference, Boston, MA, August 1991.

"Distribution Planning and DSM Assessment Using Satellite Imagery and Pattern Recognition," Pennsylvania Electric Association's System Planning Committee Meeting, Wilkes-Barre, PA; May 1991.

"DSM: Transmission and Distribution Impacts," Electric Power Research Institute Workshops, Hartford, CT, November 1987; San Diego, CA, December 1987; Chattanooga, TN, March 1988; Minneapolis, MN, March 1988; Denver, CO, March 1988.

"Purchased Energy Analysis and Energy Accounting," Open Pit Mining Association Meeting, New Orleans, LA; June 1979.

The Energy Council
"Ratemaking 101," Oklahoma City, OK, September 2018

Mississippi State Legislature Committee Sessions

"Net Metering: Issues and Solutions," Joint Legislative Hearing on Energy Efficient Homes and Buildings, Jackson, MS; November 16, 2009.

"Net Metering Concerns," House Agricultural Committee, Jackson, MS; November 12, 2008.

AFFILIATED TRAINING PROGRAMS: Power Systems and Utility Ratemaking Programs

<u>Webinar Courses</u>

EUCI Electric Cost of Service and Rate Design Series, Instructor

Session 1: "Electric Cost of Service Concepts and Methodologies," March 21, 2012.
Session 2: "Electric Rate Design Concepts and Methodologies," March 28, 2012.
Session 3: "Risk Mitigation in Electric Rate Design," April 4, 2012.

Edison Electric Institute E-Forum Lecture Series, Instructor
Sponsored by the EEI Rate and Regulatory Affairs Committee:

<u>Introduction to Alternative Regulation Series</u>:
Session I: "Rate Design to Ensure Fixed Cost Recovery: Rate Reform," March 30, 2010.

<u>Rate College Series</u>:
Session 16: "Managing Risk Through Rate Schedule Billing and Service Provisions," September 22, 2009.
Session 13: "Rate Design for the Rate Case," May 13, 2009.
Session 11: "Rate Design: Translating Costs to Rates," February 25, 2009.

Session 8: "The Embedded Cost-of-Service Study: Allocation Methodologies and Results," August 26, 2008.
Session 7: "The Embedded Cost-of-Service Study: Functionalization and Classification Methodologies," June 18, 2008.

Classroom Courses

EUCI, Instructor

"An Introduction to Electric Utility Power Systems" (1½ and 2 day courses).
"Understanding Electric Utilities" (1½ day course).

Open Enrollment Courses: Multiple venues, 2013 - Present.
In-House Courses:

- Liberia Electricity Regulatory Commission, Monrovia, Liberia, November 2020
- New York Power Authority, White Plains, NY, April 2020
- innogy Consulting, Boston MA, December 2019
- Southern California Public Power Association, Glendora, CA, September 2018
- Hawaiian Electric, Waikiki, HI, June 2018
- Belize Electricity Limited, Belize City, November 2016.
- California Public Service Commission, San Francisco, August 2014.

Wisconsin Public Utility Institute, Instructor
Sponsored Programs:

Annual EEI Advanced Rate Design Course:

- "An In-depth View of the Customer Charge," July 2016 – Present.
- "A Distribution Engineer's View of a Minimum Distribution System Methodology," 2013 -2015.
- "Demand Rate Design Methodology," July 2012.

Market Inflection Drivers for Service Utilities: Tracking the Trends Series:

- "Economics and Engineering in a New Partnership: Cost of Service," June 2017.
- "Roll of Engineering in Distribution System Cost Recovery," August 2016.

Large Public Power Council Roundtable:

- "Impact of Distributed Resources on Cost-of-Service and Rate Design," August 2016.
- "Minimum Distribution System Methodology," May 2013.

California Public Utility Commission Staff:
"Minimum Distribution System Methodology," October 2014.

Penn State University, Adjunct Professor
Sponsored Programs:

Electric Cost-of-Service and Rate Design Courses; 1989 - 2011

- Advanced School of Power Engineering, Pittsburgh, PA; (Annual 4-day course).

In-House Courses:

- Provincial Electric Authority, Bangkok, Thailand; February 2005 (2-week course).
- Panamanian Public Service Commission Staff, Panama City, Panama; April 2001 (1-week course).
- Power Finance Corporation/State Electric Boards, New Delhi, India; February - March 1996 (3-week course).
- Empressas Publicas de Medillin, Medillin, Colombia; November 1993 (1-week course).
- Jamaica Public Service company, Kingston, Jamaica; June 1993 (2-week course).

University of South Alabama, Instructor
Sponsored Programs:

Electric Cost-of-Service and Rate Design Courses; Mobile, AL, 1989 – 1996.

- Utility Rate Fundamentals Course (2½ day course).
- Strategic Utility Pricing Course (1½ day course).

In-House Courses:
- Oklahoma Gas & Electric Co., Public Service of Oklahoma, and Oklahoma Public Service Commission, Oklahoma City, OK; April 1990 (1-week course).

Electric League of Indiana, Inc., Instructor
Sponsored Programs:

The Electrification Council Series:
- "Energy Management Action Course," Indianapolis, IN; April - May 1979 (6 session course).
- "Electric Power Distribution for Industrial Plants and Commercial Buildings Course," Clarksville, Indianapolis, and Wabash IN; September - November 1978 (10 session course).

Professional Development Seminars, Inc., Instructor
"Fossil-Fired Power Plant Technologies," New Orleans, LA, September 2015 and Birmingham, AL, October 2015.

EXHIBIT

OF

LAWRENCE J. VOGT
ON BEHALF OF TAMPA ELECTRIC COMPANY

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SPONSORED OR CO-SPONSORED BY LAWRENCE J. VOGT

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C-03	Jurisdictional Net Operating Income Adjustments
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C-05	Operating Revenues Detail
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