COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ELECTRONIC APPLICATION OF DUKE ENERGY	)	
KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF	)	**CASE NO. 2017-00321**
THE ELECTRIC RATES; 2) APPROVAL OF AN	)	
ENVIRONMENTAL COMPLIANCE PLAN AND	)	
SURCHARGE MECHANISM; 3) APPROVAL OF	)	
NEW TARIFFS; 4) APPROVAL OF ACCOUNTING	)	
PRACTICES TO ESTABLISH REGULATORY ASSETS	)	
AND LIABILITIES; AND 5) ALL OTHER REQUIRED	)	
APPROVALS AND RELIEF	)	

DIRECT TESTIMONY

OF

GLENN A. WATKINS

DECEMBER 29, 2017

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia 23229.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist of Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 37-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have provided testimony relating to class cost of service and rate design before this Commission on numerous occasions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates has been retained by the Kentucky Office of the Attorney General ("OAG") to assist in its evaluation of the accuracy and reasonableness of Duke

Energy Kentucky Inc.'s ("Duke" or "Company") class cost of service study, proposed distribution of revenues by class and residential rate design. The purpose of my testimony, therefore, is to comment on Duke's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

II. CLASS COST OF SERVICE

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc.

Q. WHAT ARE THE PRIMARY DRIVERS INFLUENCING ELECTRIC UTILITY COST ALLOCATION STUDIES?

A. Although electric utility cost allocation studies tend to be somewhat complex in that several rate base and expense items are allocated based on internally generated allocation factors, all allocation factors are ultimately a direct function of class contributions to: (a) demands (kW); (b) energy usage (kWh); or, (c) number of customers. In this regard, energy usage (kWh) and number of customers are readily known and measured from billing and financial records. However, class contributions to demands (kW) are not always readily known for every rate class. That is, while some larger user class demands are known with certainty because they are metered and measured utilizing interval demand meters, other small volume class demands must be estimated based on sample data since these class' meters only measure monthly energy (kWh) usage. Because the vast majority of vertically integrated electric utilities rate base and expense account items are allocated based on some measure of demand, this is a most critical component within the cost allocation process. In other words, the estimation of class contributions to demand serve as the foundation for any class cost allocation study. Therefore, if there are deficiencies or biases within the estimation of class contributions to demand, the resulting cost allocation study will have serious deficiencies or biases and may even be meaningless.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. HAS THIS COMMISSION PROVIDED GUIDANCE AS TO WHETHER MULTIPLE COST OF SERVICE STUDIES SHOULD BE CONSIDERED?

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[1] 324 U.S. 581, 65 S. Ct. 829.

A. Yes. In Case No. 91-370 involving Union Light, Heat, and Power Company (predecessor to Duke), the Commission found the following in its Final Order:

> By having multiple cost-of-service studies presented in rate cases, the Commission is convinced that a more reasonable and informed decision can be made regarding the appropriate allocation of revenue to customer classes. [Order at 68]

Q. ARE THERE CERTAIN ASPECTS OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TEND TO BE MORE CONTROVERSIAL THAN OTHERS?

A. Yes. For decades, cost allocation experts and to some degree, utility commissions, have disagreed on how generation and transmission plant accounts should be allocated across classes. Beyond a doubt, these two issue areas are the most contentious and often have the largest impact on the results of achieved class rates of return ("ROR").

A. Generation Plant

Q. BEFORE YOU DISCUSS SPECIFIC COST ALLOCATION METHODOLOGIES, PLEASE EXPLAIN HOW GENERATION/PRODUCTION-RELATED COSTS ARE INCURRED; I.E., PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO GENERATION/PRODUCTION RESOURCES.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, generation/production facility investments are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour ("kWh") would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that Duke experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To further complicate matters, the electric utility industry is unique in that there is a distinct energy/capacity trade-off relating to generation/production costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. PLEASE EXPLAIN.

A. Total generation production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes each and every hour of the year. This would result in 8,760 hourly allocations. Although such an analysis is possible with today's technology, hourly supply (generation) and demand (customer load) data is required to conduct such hour-by-hour analyses. While most utilities can and do record hourly production output, they often do not estimate class loads on an hourly basis (at least not for every hour of the year). With these constraints in mind, several allocation methodologies have been developed to allocate electric utility generation plant investments and attendant costs. Each of these methods has strengths and weaknesses regarding the reasonableness in reflecting cost causation.

Q. APPROXIMATELY HOW MANY COST ALLOCATION METHODOLOGIES EXIST RELATING TO THE ALLOCATION OF GENERATION PLANT?

A. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[2]

Q. DOES THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL RECOGNIZE THE CAPACITY/ENERGY TRADE-OFF THAT EXISTS BETWEEN DIFFERENT TYPES OF GENERATION/PRODUCTION FACILITIES?

A. Yes. The NARUC Manual contains the following discussion regarding system planning with reference to plant cost allocation:

> Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.
>
> The utility can choose to construct one of a variety of plant types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.[3]

Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

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[2] James Bonbright, Principles of Public Utility Rates, Second Edition, 1988, page 495.
[3] NARUC Electric Utility Cost Allocation Manual, 1992, page 53.

Single Coincident Peak ("1-CP") -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning one hundred percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install are predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as Duke had a peak load of 1,000 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle and combustion turbine units, the actual total cost of installed capacity is significantly higher than if the utility only had to consider meeting 1,000 mW for 1 hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. Second, the other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a "free ride" on the assignment of generation costs that this class requires.

4-CP -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

Summer and Winter Coincident Peak ("S/W Peak") -- The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two or more hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is no more reasonable than the 1-CP method.

12-CP -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities than does the 1-CP, 4-CP, or S/W peak methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year; i.e., are planned and installed to minimize total costs (capacity and energy). Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on the system coincident load factor, i.e., the load factor that represents the portion assigned based on consumption (average demand).

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

One of the perceived benefits of the A&E method is that because a portion of generation costs are allocated based on energy usage, no class will receive a "free-ride" under this method. However, because the "excess" portion of this method is calculated as the difference between a class' non-coincident peak demand and average hourly demand, this approach often over-assigns cost responsibility to low load factor classes and almost always over-allocates costs to classes that utilize the system predominately during off-peak periods. Indeed, the A&E approach is contrary to utility system planning in that generation costs can be minimized due to customer load diversity. That is, while some classes peak during certain hours of the day, other classes will peak at other points in time. This class load diversity allows utilities to plan their generation system in such a manner that minimizes total costs. Because the arithmetic of the A&E method requires the use of class non-coincident demands, the benefits of class load diversity are not recognized.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method wherein it explicitly recognizes the capacity and energy trade-off inherent with generating facilities and specifically reflects the actual mix of a utility's resources used to serve its varying loads (demands) throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

Consistent with the NARUC Manual passage referenced earlier, a major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Finally, hydro, solar and wind units are evaluated on a case-by-case basis. There are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). With regard to solar units, generation output is compromised during cloudy weather and is non-existent (without batteries) during evening and nighttime hours. Wind generation is only possible when there is a breeze. Therefore, this type of generation is generally not regarded as being reliable for meeting peak load requirements, but rather, provides low cost energy throughout the year.

Probability of Dispatch -- The Probability of Dispatch method is the most theoretically correct and most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset's (plant or unit) investment is evaluated on an hourly basis over every hour of the year. That is, each generating unit's gross investment is assigned to individual hours based upon how that individual plant is operated during each hour of the year. In this method, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout numerous hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only a few peak hours of the year. The capacity costs for all generating units operating in a particular hour are then summed to develop the total hourly investment assigned to each hour. These hourly generating unit investments are then assigned to individual rate classes based on class contributions to system load for every hour of the year.

As a result of such analyses, the Probability of Dispatch method properly reflects the cost causation imposed by individual classes because it reflects the actual utilization of a utility's generation resources. Put differently, the assignment of generation costs is consistent with the utility's planning process to invest in a portfolio of generation resources wherein high fixed cost/low variable cost base load generation units are assigned to classes, based on these units' output, over the majority of hours during the year (because they will, on an expected basis, be called upon to operate over the majority of hours during the year). In contrast, the investment costs associated with the low fixed cost/high variable cost peaker units are assigned to those classes in proportion over relatively fewer hours during a year (because they will, on an expected basis, be called upon to operate over fewer hours). As is evident from the above discussion, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

Equivalent Peaker ("EP") -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant level of assumptions regarding the current (or future) costs of various generating alternatives.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion, cost allocation approaches that only consider a few hours of peak loads (demands) such as the 1-CP, 4-CP, and S/W methods do not reasonably reflect cost causation for electric utilities because these methods totally ignore the type and level of investments made to provide generation service. When generation cost responsibility is assigned to rate classes only on a few hours of peak demand, there is an explicit assumption that there is a direct and proportional correlation between peak load (for a few hours) and the utility's <u>total</u> investment in its portfolio of generation assets. Such is certainly not the case with utilities such as Duke wherein the portfolio of generation assets are entirely comprised of a base load coal unit coupled with combustion turbine (CT) units operated only for peaking requirements. Furthermore, the total dollar amount of generation investment for utilities such as Duke that have coal generation facilities includes a substantial, if not the majority of, its net investment to comply with environmental or pollution control requirements. These environmental or pollution control investments are related to the burning of fuel, which is energy-related.

Perhaps the simplest way to explain how a utility plans and builds its portfolio of generation assets and facilities is to consider the differences between capital costs and operating costs of various generation alternatives. Most utilities have a mix of different types of generation facilities including large base load units, intermediate plants, and small peaker units. Individual generating unit investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load coal and nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers.

Peak responsibility methods such as the 1-CP, 4-CP, and S/W peak totally ignore the planning criteria used by utilities to minimize the total cost of providing service, do not reflect the utilization of its portfolio of generating assets throughout the year, and therefore, do not reflect in any way how capital costs are incurred; i.e., do not reflect cost causation.

Q. PLEASE BRIEFLY DESCRIBE DUKE'S PORTFOLIO OF GENERATION ASSETS.

A. As discussed in the testimony of Duke witness Verderame, Duke's generation portfolio is comprised of a single base load coal facility (East Bend) and six CT peaker units at the Woodsdale Generating Station. In addition, Duke is constructing two solar facilities that will provide low cost energy when completed.

Q. WHAT COST ALLOCATION METHOD(S) DID DUKE UTILIZE TO ALLOCATE GENERATION PLANT COSTS?

A. Duke witness Ziolkowski conducted CCOSS utilizing three different methods: 12-CP; A&E; and, what he refers to as "Summer/Non-Summer" (S/NS). Of these three methods, Mr. Ziolkowski recommends reliance on the 12-CP approach.

Q. DO YOU HAVE ANY DISAGREEMENTS WITH MR. ZIOLKOWSKI'S CHARACTERIZATION OF THESE THREE METHODS?

A. Yes. On page 6 of his direct testimony, Mr. Ziolkowski claims that the A&E method "recognizes both the class average use of the system capacity and the class contribution to the capacity required to meet the maximum system load." As discussed earlier, the A&E method is based on class non-coincident peak demands and not system coincident peak demands. As such, the A&E method does not recognize the benefits of class load diversity. Although this method does recognize energy usage, it in no way recognizes "the capacity required to meet the maximum system load." Rather, the A&E approach assigns the "excess" portion based on the difference between maximum class hourly demands (regardless of when these class peaks occur) and average hourly demands.

With regard to Mr. Ziolkowski's "S/NS" approach, he claims this is a time-differentiated method. In reality, this is not a time-differentiated cost allocation approach and is nothing more than a composite weighting of the 4-CP and 12-CP methods. Specifically, and as discussed on pages 6 and 7 of his direct testimony, Mr. Ziolkowski has used a weighting of 37.69% using the 4-CP method and 62.31% using the 12-CP method.[4]

Q. DO YOU FIND MR. ZIOLKOWSKI'S CHARACTERIZATION THAT HIS "S/NS" METHOD IS TIME-DIFFERENTIATED PARTICULARLY RELEVANT?

A. Yes. In his direct testimony, Mr. Ziolkowski refers to the Commission Order in Case No. 91-00370 wherein it directed the Company to file multiple cost of service studies including the time-differentiated families of production plant allocation. As noted above, Mr. Ziolkowski's S/NS approach cannot be considered a time-differentiated cost study but is rather a methodology based on a simple weighting of the 4-CP and 12-CP approaches. In fact, in its Order in Case No. 91-370, the Commission explicitly referenced the BIP method as a time-differentiated methodology and suggested that the Company and other interested parties "may want to refer to the description of these

[4] The 4-CP utilized the four highest monthly system peak demands during June, July, August, and September.

methodologies as set forth in the NARUC's 'Electric Utility Cost Allocation Manual' which was revised in January 1992."[5]

Q. WITH REGARD TO TIME-DIFFERENTIATED STUDIES, DOES THE NARUC MANUAL REFERENCE A TIME-DIFFERENTIATED METHOD SIMILAR TO THE S/NS APPROACH DEVELOPED BY MR. ZIOLKOWSKI?

A. No. The NARUC Manual mentions four types of time-differentiated cost studies: (1) production stacking methods; (2) the BIP method; (3) Loss of Load Probability method; and, (4) Probability of Dispatch method. The NARUC Cost Allocation Manual, chapter concerning generation cost allocation methods is provided in my Schedule GAW-2.

Q. HAVE YOU CONDUCTED ALTERNATIVE STUDIES THAT MORE ACCURATELY REPRESENT THE CAPACITY AND ENERGY TRADE-OFFS EXHIBITED IN DUKE'S GENERATION PLANT INVESTMENT?

A. Yes. Although there is no single, or absolute, correct method to allocate joint generation costs, some methods are superior to others and the results of multiple, yet reasonable, methods should be considered in evaluating class revenue responsibility. While I acknowledge that the 12-CP method often produces fair and reasonable results across classes, this approach does not directly reflect the capacity/energy tradeoff that exists within a utility's (or Duke's) portfolio of generating assets and thus, does not directly reflect cost causation.

In my opinion, the BIP, P&A, and Probability of Dispatch methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. However, due to the forecasted test year utilized in this case, it is virtually impossible to realistically forecast class and system loads for each and every hour of the forecasted test year (8,760 hours), let alone, forecast how Duke's generation facilities will be dispatched every hour of the year. As such, the Probability of Dispatch is not appropriate in this case. Therefore, I have conducted alternative CCOSS utilizing the BIP and P&A methods to allocate Duke's generation costs.

[5] Case No. 91-370, Final Order, page 68.

Q. WHAT MODEL DID YOU USE TO CONDUCT YOUR ALTERNATIVE CCOSS WHEREIN GENERATION PLANT WAS ALLOCATED USING THE BIP AND P&A METHODS?

A. In conducting my alternative studies, I utilized the Company's Excel CCOSS model provided in discovery. In this regard, it should be noted that I have utilized Mr. Ziolkowski's revised model as provided in response to Staff-DR-02-088.

Q. WHAT MEASUREMENT OF PEAK DEMAND DID YOU UTILIZE WITHIN YOUR BIP AND P&A METHODS?

A. The demand component of my BIP and P&A methods utilizes class contributions to the 1-CP (highest annual system load). This approach of utilizing class contributions to the highest annual system peak demand is consistent with the spirit and intent of both the BIP and P&A methods. In my opinion, it would introduce a bias to utilize multiple system peaks (such as the 12-CP) when using methods that also consider energy usage throughout the year.

B. Transmission Plant

Q. PLEASE EXPLAIN THE THEORIES ON HOW TRANSMISSION-RELATED PLANT SHOULD BE ALLOCATED WITHIN AN EMBEDDED CCOSS.

A. There are two general philosophies relating to the proper allocation of transmission-related plant. The first philosophy is based on the premise that transmission facilities are nothing more than an extension of generation plant in that transmission facilities simply act as a conduit to provide power and energy from distant generating facilities to a utility's load center (specific service area). That is, generation facilities are often located well away from load centers and near the resources required to operate generation facilities. For example, coal generation facilities are commonly located near water sources for steam and cooling or near coal mines and/or rail facilities. Similarly, natural gas generators must be located in close proximity to large natural gas pipelines. Under this philosophy, transmission costs are allocated using the same method as that used to allocate generation-related costs.

The second philosophy relates to the physical capacity of transmission lines. That is, transmission facilities have a known and measurable load capability such that customer contributions to peak load should serve as the basis for allocating these transmission costs. While there is no doubt that any given electricity conductor (i.e., a transmission line) has a physical load carrying capability, this rationale fails to recognize cost causation in three regards.

First, an allocation based simply on contributions to a few hours of peak load fails to recognize the fact that transmission facilities are indeed an extension of generation facilities and are used to move the energy produced by the generators from remote locations to where customers actually consume electricity. Second, and similar to the concept of base load units producing energy to serve customers throughout the year, a peak responsibility approach based on one or only a few hours of maximum demand fails to recognize that transmission facilities are used virtually every hour of an entire year and not just during periods of peak load. Third, any assumption that transmission costs are related to peak load implies that there is a direct and linear relationship between cost and load. In other words, one must assume that if load increases, the cost of transmission facilities increases, in a direct and linear manner. This is simply not the case since there are significant economies of scale associated with high voltage transmission lines.

Q. WHAT METHOD DID MR. ZIOLKOWSKI USE TO ALLOCATE DUKE'S TRANSMISSION-RELATED COSTS?

A. Mr. Ziolkowski allocated transmission-related costs based on the 12-CP method.

Q. WHAT IS YOUR OPINION REGARDING THE PROPER ALLOCATION OF TRANSMISSION-RELATED COSTS?

A. In my opinion, the 12-CP approach strikes a reasonable balance between the two general philosophies that were discussed above as it relates to the cost causation and allocation of transmission-related costs. As such, I concur with Mr. Ziolkowski's allocation of transmission-related costs using the 12-CP method.

C. <u>BIP CCOSS Results</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. In order to reflect the capacity/energy trade-off inherent in Duke's mix of generating resources, each plant's maximum capacity (mW) and output (mWh) during the test year is required. Schedule GAW-3 provides the classification between energy and demand for Duke's generation plant under the BIP method. The BIP method evaluates each plant based on its capacity factor to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements. To illustrate, even though the East Bend facility can be considered a "base load" unit, it operates with a capacity factor of about 70% (69.77%). As such, East Bend has been classified and allocated as 69.77% energy and 30.23% demand.

The Company's generating units at its Woodsdale facility are all combustion turbine peaker units that only operate during a few hours of the year to serve peak loads and have a capacity factor of less than 1% (0.64%). As such, these facilities were classified and allocated as 99.36% demand-related and only 0.64% energy-related. Finally, Duke has included its three solar facilities currently under construction within its forecasted test year plant in service. Although these units are expected to have an annual capacity factor of only about 22% (21.60%), I have classified and allocated these facilities as 50% energy-related and 50% demand-related. This classification is based on the fact that Duke typically peaks during the afternoon hours in the summer. Furthermore, peak summer demands almost always occur on hot summer days with abundant sunshine. As such, it is most likely that these solar units will help contribute to peak load requirements. At the same time, these solar facilities will provide energy throughout the entire year during daylight hours

As indicated in my Schedule GAW-3, each plant's gross investment was weighted between energy and demand-related such that when all generation facilities are considered, a resulting generation classification/allocation of 50.03% energy and 49.97%

demand is produced. For purposes of my analysis, I have rounded these to 50% demand/50% energy.

Q. PLEASE PROVIDE A COMPARISON OF GENERATION ALLOCATION FACTORS UNDER MR. ZIOLKOWSKI'S 12-CP APPROACH TO THOSE OBTAINED UNDER THE BIP METHOD.

A. The following table provides a summary of class rates of return at current rates utilizing the Mr. Ziolkowski's 12-CP method and those obtained under the BIP method:

Class	Duke 12-CP	BIP
Rate RS	0.98%	1.11%
Rate DS	5.57%	5.37%
Rate GS-FL	13.92%	13.37%
Rate EH	-12.04%	-16.83%
Rate SP	9.26%	9.26%
Rate DT-Secondary	4.15%	3.86%
Rate DT-Primary	2.14%	1.92%
Rate DP	-0.09%	-0.14%
Rate TT	3.80%	3.47%
Lighting	1.19%	0.89%
Other-Water Pumping	-16.01%	-16.01%
TOTAL	2.83%	2.83%

D. Peak & Average CCOSS Results

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE P&A METHOD TO ALLOCATE GENERATION COSTS.

A. First, I calculated Duke's retail load factor in order to weight between the "peak" and "demand" portions for the P&A allocation factor. This resulted in 56.55% of generation costs being assigned based on average demand and 43.45% allocated based on peak demand.

I then utilized firm class contributions to the 1-CP demand (experienced in July) to reflect the peak nature and responsibility of class loads. The development of my P&A allocation factors is provided in my Schedule GAW-4.

Q. PLEASE PROVIDE A COMPARISON OF GENERATION ALLOCATION FACTORS UNDER MR. ZIOLKOWSKI'S 12-CP APPROACH TO THOSE OBTAINED UNDER THE P&A METHOD.

A. The following table provides a comparison of retail class allocation factors under the 6-CP and P&A methods:

Class	Duke 12-CP	P&A
Rate RS	0.98%	1.12%
Rate DS	5.57%	5.42%
Rate GS-FL	13.92%	13.30%
Rate EH	-12.04%	-15.98%
Rate SP	9.26%	9.26%
Rate DT-Secondary	4.15%	3.81%
Rate DT-Primary	2.14%	1.87%
Rate DP	-0.09%	-0.14%
Rate TT	3.80%	3.35%
Lighting	1.19%	0.80%
Other-Water Pumping	-16.01%	-16.01%
TOTAL	2.83%	2.83%

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PROPER CLASS ALLOCATION OF DUKE'S COST OF SERVICE?

A. As shown in the tables above, there are some minor differences in absolute rates of return across the 12-CP, BIP and P&A methods. However, class rates of return are directionally identical and all three methods produce reasonably similar results. As a result, I conclude that the 12-CP study results recommended by Duke serves as a reasonable basis for evaluating class profitability.

III. CLASS REVENUE DISTRIBUTION

Q. WHAT ARE THE GENERAL CRITERIA THAT SHOULD BE CONSIDERED IN ESTABLISHING CLASS REVENUE RESPONSIBILITY FOR ELECTRIC UTILITY RATES?

A. There are several criteria that should be considered in evaluating class or rate schedule revenue responsibility. Class cost allocation results should be considered, but as discussed in detail earlier in my testimony, are not surgically precise. As such, they should only be used as a guide and used as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure; affordability of electricity across various classes as well as a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria that should be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. In this regard, there is no universal mathematical methodology that can be applied across all utilities or across all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases. These include: some movement towards allocated cost of service; and, maximum/minimum percentage changes across individual rate classes.

Q. WHICH DUKE WITNESS SPONSORS THE COMPANY'S PROPOSED CLASS REVENUE DISTRIBUTION?

A. This is not entirely clear. That is, while witness Ziolkowski discusses the methodology to distribute the Company's proposed overall $48.646 million increase and also provides an attachment showing the results of this methodology, the class increases presented by Mr. Ziolkowski in his Attachment JEZ-2 do not match the revenue proof amounts sponsored by Company witness, Bruce Sailers and provided in the Company's Filing Schedule Series M. I will explain this disparity later in my testimony. Notwithstanding the disparity between these two Duke witnesses, it appears that the basic framework to distribute the Company's requested overall revenue increase was developed and sponsored by Mr. Ziolkowski.

Q. DOES MR. ZIOLKOWSKI CLAIM TO HAVE CONSIDERED THE VARIOUS SUBJECTIVE CRITERIA AS WELL AS THE BROAD PARAMETERS DISCUSSED ABOVE WITHIN HIS CLASS REVENUE DISTRIBUTION PROPOSAL?

A. To some extent, yes. Mr. Ziolkowski's revenue distribution methodology was clearly developed in recognition of gradualism wherein he refers to his recommendation to not move all classes exactly to his allocated cost of service study as an attempt to avoid rate shock. In this regard, Mr. Ziolkowski's methodology, and results, as presented in his Attachment JEZ-2 adheres to gradualism while also moving all classes closer to cost of service parity.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S PROPOSED CLASS REVENUE INCREASES TO BASE RATES.

A. As mentioned earlier, there is a disparity between Mr. Ziolkowski's proposed revenue allocation shown in his Attachment JEZ-2 and the revenue increases obtained from Mr. Sailers' revenue proof, which are based on current and Company proposed rates.[6] The following table provides a summary of the dollar and percent increases to base rates developed from Mr. Sailers' revenue proof and those shown in Mr. Ziolkowski's Attachment JEZ-2:

[6] Mr. Ziolkowski's Attachment JEZ-2 has three panels – one for each of three different cost allocation methods (12-CP, A&E, and S/NS methods). However, Mr. Ziolkowski indicates on page 7 of his direct testimony that he recommends using only the 12-CP method.

Duke
Proposed Increase to Base Rate Revenues[7]

	$ Increase		% Increase	
Class	Revenue Proof [8]	Attachment JEZ-2	Revenue Proof [9]	Attachment JEZ-2
RS	$22,855,269	$22,855,023	18.98%	18.98%
DS	$13,201,410	$12,957,571	14.67%	14.40%
GSFL	$86,768	$47,513	14.71%	8.05%
EH	$91,708	$323,605	14.71%	51.89%
SP	$3,343	$3,343	11.64%	11.64%
DT-SEC	$6,510,973	$6,142,143	14.18%	13.38%
DT-PRI	$4,040,993	$4,409,827	13.15%	14.35%
DP	$167,667	$167,668	18.09%	18.09%
TT	$1,465,379	$1,465,620	11.08%	11.09%
Lighting	$222,703	$222,693	11.79%	11.79%
TOTAL	$48,646,213	$48,646,221	15.99%	15.99%

Q. IS THE COMPANY'S PROPOSED CLASS REVENUE DISTRIBUTION REASONABLE?

A. For the Residential class (RS), yes. However, given the objectives set forth above as well as the Company's CCOSS results, I have observed what appears to be several anomalous results and proposals for the non-Residential classes. In this regard, I have focused on the increases resulting from Mr. Sailers' revenue proof as these increases are developed directly from his current and proposed rate design.

In order to understand the anomalous results obtained for several of the non-Residential classes, consider class rates of return at current rates compared to the class percentage increases as shown in the table below:

[7] Excludes rider revenue and includes fuel cost revenue.
[8] Per Schedule GAW-5.
[9] Per Schedule GAW-5.

Class	12-CP ROR @ Current Rates	Indexed ROR @ Current Rates	Duke Proposed % Increase In Base Rates
RS	0.98%	35%	18.98%
DS	5.57%	197%	14.67%
GSFL	13.92%	492%	14.71%
EH	-12.04%	-425%	14.71%
SP	9.26%	327%	11.64%
DT-SEC	4.15%	147%	14.18%
DT-PRI	2.14%	76%	13.15%
DP	-0.08%	-3%	18.09%
TT	3.80%	134%	11.08%
Lighting	1.19%	42%	11.79%
TOTAL	2.83%	100%	15.99%

As can be seen above, the GSFL class is currently producing a rate of return far in excess of the system average and in fact, is significantly higher than the Company's proposed ROR. However, Mr. Sailers' revenue proof results in this class incurring an increase of 14.71%, which is only slightly less than the system average percentage increase of 15.99%. Moreover, the GSFL percentage increase is larger than other non-Residential percentage increase (such as DS, SP, DT-SEC, DT-PRI, TT, and Lighting) even though this class' profitability is the highest on the system.

The next apparent anomaly relates to Electric Heating (Rate EH). This class' ROR is the lowest on the system (-12.04%), yet, it would incur less than the system average percentage increase (15.99%) and significantly less than the Residential percentage increase (18.98%).

Another apparent anomaly relates to Rate DT-Primary wherein this class is producing a rate of return below the system average rate of return (which would indicate the need for a larger percentage increase than the system average), Mr. Sailers' rate design results in this class receiving an increase less than the system average percentage increase.

Finally, the Lighting class is producing a rate of return below the system average and similar to that of the Residential class, yet, this class would receive an increase of only 11.79% compared to the system average percentage increase of 15.99% and the Residential increase of 18.98%.

IV. RESIDENTIAL RATE DESIGN

Q. DOES DUKE PROPOSE SIGNIFICANT INCREASES TO RESIDENTIAL FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. Duke witness Sailers proposes to increase the Residential Rate RS customer charge from $4.50 to $11.22 per month, or by 149%.

Q. HOW DOES MR. SAILERS SUPPORT HIS EXCEPTIONALLY LARGE PROPOSED INCREASE TO THE FIXED MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. Mr. Sailers provides very little support for this exceptionally large percentage increase and indicates that his proposed Residential customer charge of $11.22 was developed directly from Mr. Ziolkowski's allocated cost of service study. In Filing Schedule L (sponsored by Mr. Sailers), he indicates the following rationale for his proposed increase to the Residential customer charge:

> The customer charge is increased 149% to better reflect the customer related fixed cost to serve. This change better aligns price signals with cost causation. The energy charge recovers the remaining cost of service revenue requirement.

Q. IS DUKE'S PROPOSED INCREASE REASONABLE OR IN THE PUBLIC INTEREST?

A. No. The Company's proposed increase of 149%, violates the regulatory principle of gradualism, violates the economic theory of efficient competitive pricing, and is contrary to effective conservation efforts.

Q. DOES DUKE'S PROPOSAL TO COLLECT A SUBSTANTIAL PORTION OF RESIDENTIAL DISTRIBUTION REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL PRACTICES OF SUCH COMPETITIVE MARKETS?

A. No. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[10] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[11] It is well known that costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage, i.e. volume-based pricing.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an

[10] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

[11] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q. PLEASE EXPLAIN HOW EFFICIENT PRICING PRINCIPLES ARE APPLIED TO THE ELECTRIC UTILITY INDUSTRY.

A. Universally, utility marginal cost studies include three separate categories of marginal costs: demand, energy, and customer. Consistent with the general concept of marginal costs, each of these costs varies with incremental changes. Marginal demand costs measure the incremental change in costs resulting from an incremental change in peak load (demand). Marginal energy costs measure the incremental change in costs resulting from an incremental change in kWh (energy) consumption. Marginal customer costs measure the incremental change in costs resulting from an incremental change in number of customers.

Particularly relevant here is understanding what costs are included within, and the procedures used to determine, marginal customer costs. Since marginal customer costs reflect the measurement of how costs vary with the number of customers, they only include those costs that directly vary as a result of adding a new customer. Therefore, marginal customer costs only reflect costs such as service lines, meters, and incremental billing and accounting costs.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS DUKE.

A. Due to Duke's investment in system infrastructure, there is no debate that many of its costs are sunk costs and are therefore, characterized as fixed costs in the short-run. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, it is generally agreed in our society, and economic system, that those who receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity usage, i.e., the level of kWh (electric) consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. IS THE ELECTRIC UTILITY INDUSTRY UNIQUE IN ITS COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated, e.g., motor transportation, airline travel, and rail service.

Accordingly, Duke's position that a large portion of its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Company's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve and are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. HOW ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[12] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for and use of natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[13] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[14]

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[12] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.
[13] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.
[14] *Id.* p. 8 (alteration in original).

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[15]

Recently, some public utilities have begun to advocate SFV Residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

[15] *Id.* pp. 128-129.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH DUKE'S RESIDENTIAL CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include a return (margin), interest, and depreciation associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO DUKE'S RESIDENTIAL CLASS?

A. Yes. I conducted a direct customer cost analysis for Duke's Residential Rate Schedule RS. The details of this analysis are provided in my Schedule GAW-6. As indicated in this Schedule, the Residential Rate Schedule RS direct customer cost is calculated to be between $2.69 and $3.49 per month at the Company's requested 10.30% return on equity.

Q. MR. SAILERS INDICATED THAT HIS PROPOSED RESIDENTIAL CUSTOMER CHARGE OF $11.22 IS TAKEN DIRECTLY FROM MR. ZIOLKOWSKI'S COST OF SERVICE STUDY. PLEASE EXPLAIN THE VAST DIFFERENCE BETWEEN MR. ZIOLKOWSKI'S CALCULATED RESIDENTIAL CUSTOMER COST OF $11.37[16] AND YOUR CALCULATED CUSTOMER COST OF $2.69 TO $3.49 PER MONTH.

A. Mr. Sailers' reference to Residential customer-related costs of $11.22 is taken from the fully allocated cost study conducted by Mr. Ziolkowski. In conducting his CCOSS, Mr. Ziolkowski classified every rate base and expense item as energy-related, demand-related, or customer-related. In conducting his study, Mr. Ziolkowski classified distribution plant such as poles, overhead lines, and underground lines as partially customer-related and partially demand-related. As a result, a portion of the Company's distribution system upstream from the customer's service line is included within Mr. Ziolkowski's calculation of "customer" costs.

While there is no true "customer" component of poles and distribution conductors, this classification may be appropriate for class cost allocation purposes due to different densities and mixes of customers throughout the Company's service area such that the allocation of these investments and expenses result in a fair assignment of costs across classes. However, it should not be inferred that these costs are in any way required to connect a customer. For example, it makes no sense to infer that 24% of a

[16] Mr. Ziolkowski calculated a customer cost of $11.37 per month wherein Mr. Sailers' calculated $11.22 per month on his Attachment BLS-2. The difference between these two numbers is the number of annual customer bills utilized by Mr. Ziolkowski and Mr. Sailers.

distribution conductor (circuit) is required to connect a customer to the system.[17] Indeed, the cost of the conductor is there to meet the collective energy needs of its consumers within that circuit and is planned, and sized, to meet the collective maximum loads of those consumers. Put differently, if an additional customer is added to the distribution system, the Company will not incur additional pole or conductor investment costs in order to serve this new customer. As such, the classification of distribution plant is no more than a convenient, fair, and equitable way to allocate distribution costs across rate classes. However, because of the way Mr. Ziolkowski places all costs into various classification "buckets," his calculations place a significant level of poles, conductors, and conduit within the customer cost "bucket." Furthermore, the Company's expenses are also placed in one of the three classification "buckets" and are generally calculated based on plant allocations or previously classified expense amounts. As such, a significant amount of the Company's expenses and other rate base items, including overhead costs are also placed into the customer cost "bucket." Specifically, the following other costs are inappropriately included by Mr. Ziolkowski within his Residential "customer" costs:

<u>Expenses</u>	
Uncollectible Expenses	$560,462
Sale of Accts. Receivable	$908,804
Sales Expense	$607,008
A&G Expenses	$3,173,557
Depreciation of Gen'l & Common Plant	$440,141
<u>Rate Base</u>	
General Plant	$4,364,038
Common Plant	$4,781,671

Q. IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT THESE DISTRIBUTION COSTS CLASSIFIED AS "CUSTOMER-RELATED," AS WELL AS A SIGNIFICANT PORTION OF THE COMPANY'S OVERHEAD EXPENSES, ARE NOT PROPERLY CONSIDERED AS TRUE CUSTOMER COSTS?

[17] Mr. Ziolkowski has classified distribution poles and conductors as 24.31% customer-related and 75.69% demand-related.

A. In his well-known treatise Principles of Public Utility Rates, Professor James C. Bonbright states:

> . . . 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 our 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 fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." **They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.** [Emphasis added] (Second Edition, page 492)

Q. WHAT IS YOUR RECOMMENDATION REGARDING RESIDENTIAL CUSTOMER CHARGES?

A. Considering that the direct customer cost associated with connecting and maintaining a customer's account is considerably less than the current monthly customer charge of $4.50, I recommend no increase to this charge.

Q. HAVE YOU REVIEWED THE COMPANY'S REQUEST FOR THE COMMISSION TO APPROVE A "FIXED BILL" BILLING PRODUCT?

A. Yes. I have reviewed the testimony of Company witness Alexander Weintraub as well as various data request responses relating to this issue.

Q. PLEASE BRIEFLY EXPLAIN THE COMPANY'S REQUEST TO IMPLEMENT A "FIXED BILL" BILLING PRODUCT.

A. Under the Company's proposal, qualified Residential customers would have the option of contracting for a fixed total electric bill for a 12-month period regardless of the customers' energy usage over this 12-month period. Unlike the current budget billing plan, the flat monthly billing charge would be guaranteed for a 12-month period with no true-up. In developing the fixed charge (spread over 12-months), the Company will estimate each customer's usage based on historical consumption as well as under normal weather conditions. In exchange for a guaranteed bill regardless of weather conditions and usage, the customer's bill would reflect a premium above the current authorized Residential rates.

Q. WHAT PREMIUM WOULD BE CHARGED OVER AND ABOVE THE CURRENT AUTHORIZED RESIDENTIAL RATES?

A. The Company has not quantified or set forth a specific proposal as to what this premium would be. In response to AG-DR-02-29(d), the Company stated as follows:

> The premium or incremental cost associated that will be included in a customer's monthly Fixed Bill will be clearly explained in the compliance tariff for the program.

However, in response to AG-DR-02-33, the Company indicated that it has not yet developed marketing materials relating to its Fixed Bill program for Kentucky, but has included materials used in Indiana (that has a similar Fixed Bill program). The Indiana material states that a customer's fixed bill is calculated by applying that customers expected usage and prices with the program fee not to exceed 7.5%. Furthermore, the Company indicated that expected usage is calculated by analyzing each customer's past usage patterns and applying them to average weather for each month. It should be noted that the Company's response to AG-DR-02-33 states that the Fixed Bill Kentucky will not be exactly the same as Fixed Bill Indiana.

In short, I have not been able to find any specifications or quantification as to the level of premium the Company would charge under this proposed program.

Q. DO YOU SUPPORT THE COMPANY'S PROPOSED VOLUNTARY FIXED BILL OPTION?

A. No.

Q. PLEASE EXPLAIN.

A. From an economic and public policy perspective, the Fixed Bill program is a bad idea and not in the public interest. This program merely provides windfall profits to Duke with no realistic benefits to consumers. The proposed Fixed Bill program would send the worst possible signal to customers to conserve energy and/or reduce peak period usage. As proposed, the Fixed Bill program would provide for a constant "flat" bill to customers regardless of how much energy they consume or when they use this electricity. Policies in which there is an incentive to increase peak load or total consumption are totally contrary to the objectives of efficient pricing and the electrical needs of all consumers.

To illustrate the economically incorrect signals provided to consumers under the Fixed Bill program, consider a very hot Kentucky day in which the temperature climbs into the high 90's or low 100's. Duke's system is strained to the limit to provide power (at a very high incremental cost) to all customers, yet the Fixed Bill customer will in all likelihood turn his/her thermostat to a lower temperature to maintain the same level of comfort as when the temperature is in the 70's and Duke is operating with ease. Similarly, during extremely cold weather days, a Fixed Bill customer will be well aware that there are no economic reasons to conserve energy on these days and will therefore, simply turn up their thermostats.

During peak days, which are dictated by weather conditions, Duke's incremental energy cost to produce electricity are higher than they are during milder weather conditions. This in turn, increases all customers' fuel rates yet, there would be no consequence to the Fixed Bill customers who increase their loads due to the extreme weather conditions.

Q. DOES THE BUDGET BILLING PROGRAM SUFFER FROM THE SAME INEFFICIENT PRICE SIGNALS AS THE PROPOSED FIXED BILL PROGRAM?

A. To some extent, yes. However, there is a major difference in the two programs. Under the Budget Billing program, the customers at least know that any decisions to inefficiently increase consumption must be paid for at some point in time. Under the Fixed Bill program, these inefficient decisions will never be paid for.

Q. IF A CUSTOMER CONSISTENTLY USES MORE ENERGY THROUGHOUT THE TERM OF THE FIRST YEAR'S CONTRACT, WOULD THIS CUSTOMER'S FIXED BILL BE INCREASED IN SUBSEQUENT YEARS?

A. Not necessarily. First, it is my understanding that each customers' annual fixed bill will be based on a regression of multiple year's usage, not just the most recent. Furthermore, after the one year commitment is over, a customer is free to go back to the traditional Residential rate schedule. However, in my opinion, the most important point to remember is that the proposed Fixed Bill program will provide incentives for customers to use more electricity, at least on a short-term basis during peak load periods.

Q. PLEASE DISCUSS THE PUBLIC POLICY PROBLEMS ASSOCIATED WITH THE PROPOSED FIXED BILL PROGRAM.

A. There is absolutely no way that the Commission Staff or an individual customer can determine if Duke will reasonably estimate a "fixed bill." The estimation of expected consumption is extremely discretionary on the part of Duke, as is the discretionary aspect of the profit "adder" allowed by the Commission. Indeed, there is a clear incentive for Duke's representatives to overstate a customer's expected usage as this will increase the revenues generated under the contract. The customer has no idea of what a reasonable level of "expected" usage would be, and has no ability to calculate the effects of abnormal versus normal weather. In these regards, legal counsel for the Attorney General has advised me that there are specific Kentucky statutes concerning consumer protection.[18] The Attorney General is concerned that consumers may not fully understand all aspects of how the fixed bill is determined, nor clearly understand the ramifications of using more or less electricity than would otherwise be the case. Therefore, the advertisements for the program, if approved, must clearly indicate to customers their options and the ramifications of their choices.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S PROPOSED FIXED BILL PROGRAM?

A. It should be rejected.

[18] In particular, KRS Chapter 367.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))	CASE NO. 2017-00321

AFFIDAVIT OF Glenn A. Watkins

Commonwealth of Virginia)

Glenn A. Watkins, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and Schedules attached thereto were prepared by him or under his direct supervision. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief, his statements made are true and correct. Further affiant sayeth naught.

[signature]

SUBSCRIBED AND SWORN to before me this 27th day of December, 2017.

[signature]
NOTARY PUBLIC

My Commission Expires: 10/31/2018

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2018
COMMONWEALTH OF VIRGINIA

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

PRESIDENT/SENIOR ECONOMIST

TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. <u>Public Utility Regulation</u>

A. <u>Costing Studies</u> -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. <u>Rate Design Studies</u> -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI=s administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. <u>Anti-Trust and Commercial Business Damage Litigation</u>

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

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CHAPTER 4

EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS

	Cost Classes			
Functions	**Demand**	**Energy**	**Customer**	**Revenue**
Production				
Thermal	X	X	N/A	N/A
Hydro	X	X	N/A	N/A
Other	X	X	N/A	N/A
Transmission	X	X	X	N/A
Distribution	X	X	X	N/A
OH/UG Lines	X	X	X	N/A
Substations	X	X	X	N/A
Services	N/A	N/A	X	N/A
Meters	N/A	N/A	X	N/A
Customer	N/A	N/A	X	X

III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

CLASSIFICATION OF RATE BASE[1]

Production Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	-
330-336	Hydraulic Production	x	x[2]
340-346	Other Production	x	-

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant
Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

Maintencance

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x

Hydraulic Power Generation Operation

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-

Maintenance

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

CLASSIFICATION OF EXPENSES[1]

Other Power Generation Operation

FERC Uniform System of Account	Description	Demand Related	Energy Related
546, 548-554	All Accounts	x	-
547	Fuel	-	x

Other Power Supply Expenses

FERC Uniform System of Account	Description	Demand Related	Energy Related
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

TABLE 4-1

CLASS MW DEMANDS AT THE GENERATION LEVL IN THE TWELVE MONTHLY SYSTEM PEAK HOURS

(1988 Example Data)

Rate Class	January	February	March	April	May	June	July	August
DOM	3,887	3,863	2,669	2,103	2,881	3,338	4,537	4,735
LSMP	3,065	3,020	3,743	4,340	4,390	4,725	5,106	5,062
LP	2,536	2,401	2,818	2,888	3,102	3,067	3,219	3,347
AG&P	84	117	144	232	405	453	450	447
SL	94	105	28	0	0	0	0	0
Total	9,666	9,506	9,402	9,563	11,318	11,583	13,312	13,591

Rate Class	September	October	November	December	Total	Average
DOM	4,202	2,534	3,434	4,086	42,268	3,522
LSMP	5,106	4,736	3,644	3,137	50,614	4,218
LP	3,404	3,170	2,786	2,444	35,181	2,932
AG&P	360	284	138	75	3,189	266
SL	0	0	103	126	457	38
Total	13,072	10,724	10,105	9,868	131,709	10,976

Note: The rate classes and their abbreviations for the example utility are as follows:

DOM - Domestic Service
LSMP - Lighting, Small and Medium Power
LP - Large Power
AG&P - Agricultural and Pumping
SL - Street Lighting

TABLE 4-2
CLASS MW DEMANDS AT THE GENERATION LEVEL IN THE 3 SUMMER AND 3 WINTER SYSTEM PEAK HOURS
(1988 Example Data)

	Winter				Summer			
Rate Class	January	February	December	Average	July	August	September	Average
DOM	3,887	3,863	4,086	3,946	4,537	4,735	4,202	4,491
LSMP	3,065	3,020	3,137	3,074	5,106	5,062	5,106	5,092
LP	2,536	2,401	2,444	2,460	3,219	3,347	3,404	3,323
A&P	84	117	75	92	450	447	360	419
SL	94	105	126	108	0	0	0	0
Total	9,666	9,506	9,868	9,680	13,312	13,591	13,072	13,325

Peak demand methods include the single coincident peak method, the summer and winter peak method, the twelve monthly coincident peak method, multiple coincident peak method, and an all peak hours approach. Energy weighting methods include the average and excess method, equivalent peaker method, the base and peak method, and methods using judgmentally determined energy weightings, such as the peak and average method and variants thereof.

A. Peak Demand Methods

Cost of service methods that utilize a peak demand approach are characterized by two features: First, all production plant costs are classified as demand-related. Second, these costs are allocated among the rate classes on factors that measure the class contribution to system peak. A customer or class of customers contributes to the system maximum peak to the extent that it is imposing demand at the time of -- coincident with -- the system peak. The customer's demand at the time of the system peak is that customer's "coincident" peak. The variations in the methods are generally around the number of system peak hours analyzed, which inturn depends on the utility's annual load shape and on system planning considerations.

Peak demand methods do not allocate production plant costs to classes whose usage occurs outside peak hours, to interruptible (curtailable) customers.

TABLE 4-3
DEMAND ALLOCATION FACTORS

Rate Class	MW Demand At Annual System Peak (MW)	1 CP Alloc. Factor (Percent)	Average of the 12 Monthly CP Demands (MW)	12 CP Alloc. Factor (Percent)	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	3S/3W Alloc. Factor (Percent)	Noncoinc. Peak Demand MW	NCP Alloc. Factor (Percent)
DOM	4,735	34.84	3,522	32.09	4,491	3,946	36.67	5,357	36.94
LSMP	5,062	37.25	4,218	38.43	5,092	3,074	35.50	5,062	34.91
LP	3,347	24.63	2,932	26.71	3,323	2,460	25.14	3,385	23.34
AG&P	447	3.29	266	2.42	419	92	2.22	572	3.94
SL	0	0.00	38	0.35	0	108	0.47	126	0.87
Total	13,591	100.00	10,976	100.00	13,325	9,680	100.00	14,502	100.0

Note: Some columns may not add to indicated totals due to rounding.

TABLE 4-4

ENERGY ALLOCATION FACTORS

Rate Class	Total Annual Energy Used (MWH)	Total Energy Allocation Factor (%)	On-Peak Energy Cons. (MWH)	On-Peak Energy Allocation Factor (%)	Off-Peak Energy Cons. (MWH)	Off-Peak Energy Allocation Factor (%)
DOM	21,433,001	30.96	3,950,368	32.13	17,482,633	30.71
LSMP	23,439,008	33.86	4.452,310	36.21	18,986,698	33.35
LP	21,602,999	31.21	3,474,929	28.26	18,128,070	31.85
AG&P	2,229,000	3.22	335,865	2.73	1,893,135	3.33
SL	513,600	0.74	80,889	0.66	432,711	0.76
Total	69,217,608	100.00	12,294,361	100.00	56,923,247	100.00

Note: Some columns may not add to indicated totals due to rounding.

1. Single Coincident Peak Method (1-CP)

Objective: The objective of the single coincident peak method is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load.

Data Requirements: The 1-CP method uses recorded and/or estimated monthly class peak demands. In a large system, this may require complex statistical sampling and data manipulation. A competent load research effort is a valuable asset.

Implementation: Table 4-1 contains illustrative load data for five customer classes for 12 months of a test year. The analyst simply translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements; that is, to the revenue requirements that are functionalized to production and classified to demand. This operation is shown in Table 4-5.

TABLE 4-5

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SINGLE COINCIDENT PEAK METHOD

Rate Class	MW Demand at Generator at System Peak	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	4,735	34.84	369,461,692
LSMP	5,062	37.25	394,976,787
LP	3,347	24.63	261,159,089
AG&P	447	3.29	34,878,432
SL	0	0.00	0
TOTAL	13,591	100.00	$ 1,060,476,000

2. Summer and Winter Peak Method

Objective: The objective of the summer and winter peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. If the summer and winter peaks are close in value, and if both significantly affect the utility's generation expansion planning, this approach may be appropriate.

Implementation: The number of summer and winter peak hours may be determined judgmentally or by applying specified criteria. One method is simply to average the class contributions to the summer peak hour demand and the winter peak hour demand. Another method is to choose those summer and winter hours where the peak demand or reliability index passes a specified threshold value. Clearly, the selection of the hours is critical and the establishment of selection criteria is particularly important. These cost of service judgements must be made jointly with system planners and supported with good data. The analyst should review FERC cases, where this issue often comes up. Table 4-6 shows the allocators and resulting allocations of production plant revenue responsibility for the example using the three highest summer and three highest winter coincident peak demand hours.

TABLE 4-6

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SUMMER AND WINTER PEAK METHOD

Rate Class	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	Demand Allocation Factor	Total Class Production Plant Revenue Requirmt
DOM	4,491	3,946	36.67	388,925,712
LSMP	5,092	3,074	35.50	376,433,254
LP	3,323	2,460	25.14	266,582,600
AG&P	419	92	2.22	23,555,889
SL	0	108	0.47	4,978,544
TOTAL	13,325	9,680	100.00	$ 1,060,476,000

3. The Sum of the Twelve Monthly Coincident Peak (12 CP) Method

Objective: This method uses an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky. The 12-CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs or other reliability index values in all months.

Data Requirements: Reliable monthly load research data for each class of customers and for the total system is the minimum data requirement. The data can be recorded and/or estimated.

Implementation: Table 4-7 shows the derivation of the 12 CP allocator and the resulting allocation of production plant costs for the example case.

TABLE 4-7

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE TWELVE COINCIDENT PEAK METHOD

Rate Class	Average of 12 Coincident Peaks At Generation (MW)	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,522	32.09	340,287,579
LSMP	4,218	38.43	407,533,507
LP	2,932	26.71	283,283,130
AG&P	266	2.42	25,700,311
SL	38	0.35	3,671,473
TOTAL	10,976	100.00	$ 1,060,476,000

4. Multiple Coincident Peak Method

This section discusses the general approach of using the classes' demands in a certain number of hours to derive the allocation factors for production plant costs. The number of hours may be determined judgmentally; e.g., the 10 or 20 hours in the year with the highest system demands, or by applying specified criteria. Criteria for determining which hours to use include: (1) all hours of the year with demands within 5 percent or 10 percent of the system's peak demand, and (2) all hours of the year in which a specified reliability index (loss of load probability, loss of load hours, expected unserved energy, or reserve margin) passes an established threshold value. This may result in a fairly large number of hours being included in the development of the demand allocator.

5. All Peak Hours Approach

This method resembles the multiple CP approach except it bases the allocation of demand-related production plant costs on the classes' contributions to all defined, rather than certain specified, on-peak hours. This method requires scrutiny of all hours of the year to determine which are most likely to contribute to the need for the utility to add production plant. If the on-peak rating periods -- i.e., the hours or periods in which on-peak rates apply -- are properly defined, then all hours in the on-peak period are critical from the utility's planning perspective. Table 4-8 shows the allocators and resulting cost allocation based on the classes' shares of on-peak KWH for the example utility. For the example utility, the on-peak periods are from 5:00 p.m. to 9:00 p.m. on winter weekdays and from 12:00 noon to 6:00 p.m. on summer weekdays.

The on-peak hours may be defined using various criteria, such as those hours with a preponderance of actual peak demands, those with the majority of annual loss of load probabilities, loss of load hours or those in which other reliability indexes register critical values. Using this method requires satisfactory load research and computer capability to estimate the classes' loads in the defined on-peak periods.

TABLE 4-8

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE ALL PEAK HOURS APPROACH

Rate Class	Class On-Peak MWH At Generation	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,950,368	32.13	340,747,311
LSMP	4,452,310	36.21	384,043,376
LP	3,474,929	28.26	299,737,319
AG&P	335,865	2.73	28,970,743
SL	80,889	0.66	6,977,251
TOTAL	12,294,361	100.00	$ 1,060,476,000

Notes: The on-peak periods for the example utility are from 5:00 p.m. to 9:00 p.m. on weekdays in January through May and October through December, and from 12:00 noon to 6:00 p.m. on weekdays in June through September. Some columns may not add to indicated totals due to rounding.

6. Summary: Peak Demand Responsibility Methods

Table 4-9 is a summary of the allocation factors and revenue allocations for the methods described above. The most important observations to be drawn from this information are:

- The number of hours chosen as the basis for the demand allocator can have a significant effect on the revenue allocation, even for relatively small numbers of hours.
- The greater the number of hours used, the more the allocation will reflect energy requirements. If all 8,760 hours of a year were used, the demand and a KWH (energy) allocation factors would be the same.

TABLE 4-9

SUMMARY OF ALLOCATION FACTORS AND REVENUE RESPONSIBILITY FOR PEAK DEMAND COST ALLOCATION METHODS

	1 CP Method		3 Summer and 3 Winter Peak Method	
Rate Class	**Allocation Factor (%)**	**Revenue Requirement**	**Allocation Factor (%)**	**Revenue Requirement**
DOM	34.84	369,461,692	36.67	388,925,712
LSMP	37.25	394,976,787	35.50	376,433,254
LP	24.63	261,159,089	25.14	266,582,600
AG&P	3.29	34,878,432	2.22	23,555,889
SL	0.00	0	0.47	4,978,544
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

	12 CP Method		All Peak Hours Approach	
Rate Class	**Allocation Factor (%)**	**Revenue Requirement**	**Allocation Factor (%)**	**Revenue Requirement**
DOM	32.09	340,287,579	32.13	340,747,311
LSMP	38.43	407,533,507	36.21	384,043,376
LP	26.71	283,283,130	28.26	299,737,319
AG&P	2.42	25,700,311	2.73	28,970,743
SL	0.35	3,671,473	0.66	6,977,251
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

Note: Some columns may not add to totals due to rounding.

B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

Rate Class	Energy Allocation Factor - Average MW	Energy Allocatn. Factor (%)	Energy-Related Production Plant Revenue Requirement	Excess Demand Allocation Factor (NCP MW - Avg. MW)	Excess Demand Alloctn. Factor (Percent)	Demand-Related Production Plant Revenue Requirement	Class Production Plant Revenue Requiremnt
DOM	2,440	30.96	190,387,863	2,917	44.05	196,294,822	386,682,685
LSMP	2,669	33.87	208,256,232	2,393	36.14	161,033,085	369,289,317
LP	2,459	31.21	191,870,391	926	13.98	62,313,680	254,184,071
AG&P	254	3.22	19,819,064	318	4.80	21,399,298	41,218,363
SL	58	0.74	4,525,613	68	1.03	4,575,951	9,101,564
TOTAL	7,880	100.00	614,859,163	6,622	100.00	445,616,837	1,060,476,000

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

2. Equivalent Peaker Methods

Objective: Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

Data Requirements: This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

A Digression on System Planning with Reference to Plant Cost Allocation:

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

Classification of Generation:

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

A variant of the above approach is to do the equivalent peaker cost evaluations based only on the viable generation alternatives available to the utility at any point in time. For example, combined cycle technology might be so much more cost-effective than the next best option that it would be the preferred choice for demand lasting as little as 50 to 100 hours. If so, then using a combustion turbine as the equivalent peaker "benchmark" might be inappropriate. Such choices would require careful analysis of alternate generation expansion paths on a case by case basis.

Consider the example shown in Table 4-11. The example utility has three 100 MW combustion turbines of varying ages. All investment in these units is classified as demand-related. The utility also has three unscrubbed coal-fired units of varying ages. The production plant costs of these units are classified as follows: first, the ratio of the cost of a new CT ($300/KW) to the cost of a new unscrubbed coal unit ($1000/KW) is calculated and found to be 30 percent. Then, this factor is multiplied by the rate base for each plant, and the result is classified as demand-related, with the remainder classified as energy-related. The cost of the utility's new, scrubbed coal unit is classified by the same method. Since the unit cost is $1200/KW, only 25 percent of it ($300/KW)/($1200/KW) is classified as demand-related, with the remaining three-fourths classified as energy-related. Treating the utility's nuclear unit similarly, only 15 percent of its cost ($300/KW)/($2000/KW) is classified as demand-related.

TABLE 4-11

ILLUSTRATION OF DEMAND AND ENERGY AND ENERGY CLASSIFICATION OF GENERATING UNITS USING THE EQUIVALENT PEAKER METHOD

Unit	Unit Type	Capacity (MW)	Rate Base	Percent Class Demand-Related	Demand-Related Rate Base	Energy-Related Rate Base
A	CT	100	10,000,000	100	10,000,000	0
B	CT	100	20,000,000	100	20,000,000	0
C	CT	100	30,000,000	100	30,000,000	0
D	Coal	200	80,000,000	30	24,000,000	56,000,000
E	Coal	250	100,000,000	30	30,000,000	70,000,000
F	Coal	450	270,000,000	30	81,000,000	189,000,000
G	Coal W/FDG	600	720,000,000	25	180,000,000	540,000,000
H	Nuclear	900	1,800,000,000	15	270,000,000	1,530,000,000
TOTAL		2,700	$ 3,030,000,000	21	$ 645,000,000	$ 2,385,000,000

The equivalent peaker classification method applied in the example above ignores the fuel savings that accrue from running a base unit rather than a peaker. Discussions with planners can help incorporate the effects of fuel savings into the classification.

Table 4-12 shows the revenue responsibility for the rate classes using the equivalent peaker cost method applied to the example utility's data. In this example, a summer and winter peak demand allocator was used to allocate the demand-related costs. Observe that the total revenue requirement allocation among the rate classes is significantly different from that resulting from any of the pure peak demand responsibility methods.

TABLE 4-12

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE EQUIVALENT PEAKER COST METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requiremnt
DOM	36.67	78,980,827	30.96	261,678,643	340,659,471
LSMP	35.50	76,460,850	33.87	286,237,828	362,698,678
LP	25.14	54,147,205	31.21	263,716,305	317,863,510
AG&P	2.22	4,781,495	3.22	27,240,318	32,021,813
SL	0.47	1,012,299	0.74	6,220,230	7,232,529
TOTAL	100.00	215,382,676	100.00	845,093,324	$1,060,476,000

Note: Some columns may not add to indicated totals due to rounding.

3. Base and Peak Method

Objective: The objective of the base and peak method is to reflect in cost allocation the argument that an on-peak kilowatt-hour costs more than an off-peak kilowatt-hour and that the extra cost should be borne by the customers imposing it. This approach first identifies the same production plant cost components as the equivalent peaker cost method, and allocates demand-related production plant costs in the same way. The difference is that, using the base and peak method, the energy-related excess capital costs are allocated on the basis of the classes' proportions of on-peak energy use instead of being allocated according to the classes' shares of total system energy use. The logic of this approach is that the extra capital costs would be incurred once the system was expected to run for a certain minimum number of hours; i.e., once the break-even point in unit run time between a peaker and a baseload (or intermediate) unit was reached. However, system planners generally recognize no difference between on-peak hours and off-peak energy loads on the decision to build a baseload power plant, instead, the belief is that system planners consider the total annual energy loads that determine the type of plant to build. To allocate energy-related production plant costs on the basis of only on-peak energy use implies a differential impact of on-peak KWH as compared to off-peak KWH that may or may not exist.

Table 4-13 shows the results of a base and peak cost of service method for the example utility.

TABLE 4-13

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE BASE AND PEAK METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor On-Peak MWH	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	78,980,827	32.13	271,541,532	350,522,360
LSMP	35.50	76,460,850	36.21	306,044,166	382,505,016
LP	25.14	54,147,205	28.26	238,860,669	293,007,874
AG&P	2.22	4,781,495	2.73	23,086,785	27,868,280
SL	0.47	1,012,299	0.66	5,560,171	6,572,470
TOTAL	100.00	215,382,676	100.00	845,093,324	$1,060,476,000

Note: Some columns may not add to indicated totals due to rounding.

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	198,081,400	30.96	137,226,133	335,307,533
LSMP	38.43	237,225,254	33.87	150,105,143	387,330,397
LP	26.71	164,899,110	31.21	138,294,697	303,193,807
AG&P	2.42	14,960,151	3.22	14,285,015	29,245,167
SL	0.35	2,137,164	0.74	3,261,933	5,399,097
TOTAL	100.00	617,303,080	100.00	443,172,920	$1,060,476,000

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT
COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36,46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

	EQUIVALENT PEAKER COST METHOD		BASE AND PEAK METHOD		1 CP AND AVERAGE DEMAND METHOD		12 CP AND 1/13th AVERAGE DEMAND METHOD		PRODUCTION STACKING METHOD	
Rate Class	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 340,657,471	32.12	$ 3350,522,360	33.05	$ 354,381,313	33.42	$ 339,370,900	32.00	$ 334,590,738	31.55
LSMP	362,698,678	34.20	382,505,016	36.07	381,842,722	36.01	403,814,709	38.08	360,965,510	34.04
LP	317,863,510	29.97	293,007,874	27.63	286,764,179	27.04	286,948,099	27.06	324,315,213	30.58
AG&P	32,021,813	3.02	27,868,280	2.63	34,623,156	3.36	26,352,815	2.48	33,089,034	3.12
SL	7,232,529	0.68	6,572,470	0.62	2,864,631	0.27	3,989,478	0.38	7,515,505	0.71
Total	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00

5. Summary

Table 4-18 summarizes the percentage allocation factors and revenue allocations for the cost of service methodologies presented in this chapter. Important observations are: (1) that the proportions of production plant costs classified as demand-related and energy-related can have dramatic effects on the revenue allocation; and (2) the greater the proportion classified as energy-related, the greater is the revenue responsibility of high load factor classes and the less is the revenue responsibility of low-load factor classes.

V. FUEL EXPENSE DATA

Fuel expense data can be obtained from the FERC Form 1. Aggregate fuel expense data by generation type is found in Accounts 501, 518, and 547. Annual fuel expense by fuel type for specified generating stations can be found on pages 402 and 411 of Form 1.

Fuel expense is almost always classified as energy-related. It is allocated using appropriate time-differentiated allocators; e.g., on-peak KWH and off-peak KWH, or non-time-differentiated energy allocators (total KWH) calculated by incorporating adjustments to reflect different line and transformation losses at different levels of the utility's transmission and distribution system. Depending on the cost of service method used, it may be necessary to directly assign fuel expense to classes that are directly assigned the cost responsibility for specific generating units. Table 4-19 shows the allocation of fuel expense, other operation and maintenance expenses and purchased power expenses for the example utility. Fuel and purchased power expenses were allocated according to the classes' energy use at the generator level. Other operation and maintenance expenses were allocated using demand and energy allocators and ratio methods.

VI. OTHER OPERATIONS AND MAINTENANCE EXPENSES FOR PRODUCTION

Other production O&M costs may also be classified as demand-related or energy-related. Typically, any costs that vary directly with the amount of energy produced, such as purchased steam, variable water cost and water treatment chemical costs, are classified as energy-related and allocated using appropriate energy allocation factors. Such cost items would typically be booked in Accounts 502 through 505 for fossil power steam generation, Accounts 519 and 520 for nuclear power generation, and Accounts 548 and 550.1 for other generation (excluding hydroelectric).

TABLE 4-19
ALLOCATED GENERATION FUEL, OPERATION, AND MAINTENANCE EXPENSES
(Thousands of Dollars)

EXPENSE CATEGORY	TOTAL COMPANY RETAIL	DOMESTIC	LIGHTING, SMALL AND MEDIUM POWER	LARGE POWER	AGRICULTURAL AND PUMPING	STREET LIGHTING
Total Fuel	$ 871,598	$269,887	$295,147	$272,028	$28,068	$ 6,467
Steam Generation Expenses						
Operation Expenses	53,740	17,246	20,652	14,355	1,301	186
Maintenance Expenses	176,117	54,632	60,037	54,574	5,601	1,272
Total Steam Excl. Fuel	229,857	71,879	80,688	68,929	6,902	1,459
Nuclear Generation Expenses						
Operation Expenses	106,851	34,291	41,061	28,541	2,587	371
Maintenance Expenses	88,787	27,552	30,305	27,475	2,817	638
Total Nuclear Excl. Fuel	195,638	61,842	71,366	56,017	5,404	1,009
Hydraulic Generation Expenses						
Operation Expenses	9,730	3,054	3,462	2,872	284	58
Maintenance Expenses	13,135	4,123	4,674	3,877	383	78
Total Hydraulic Expenses	22,865	7,177	8,136	6,749	667	136
Other Generation Expenses						
Operation Expenses	20,461	6,563	7,953	5,358	516	70
Maintenance Expenses	10,371	3,327	4,020	2,729	259	36
Total Other Excl. Fuel	30,832	9,890	11,973	8,087	775	106
Purchased Power	1,275,663	395,005	431,975	398,138	41,080	9,466
System Control & Dispatch	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total	$2,626,453	$815,680	$899,285	$809,948	$82,896	$18,643

Note: Some values may not add to indicated totals or sub-totals due to rounding.

Operations and maintenance costs that do not vary directly with energy output may be classified and allocated by different methods. If certain costs are specifically related to serving particular rate classes, they are directly assigned. Some accounts may be easily identified as being all demand-related or all energy-related; these may then be allocated using appropriate demand andenergy allocators. Other accounts contain both demand-related and energy-related components. One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related. Another common method is to classify each account according to its "predominant" -- i.e., demand-related or energy-related -- character. Certain supervision and engineering expenses can be classified on the basis of the prior classification of O&M accounts to which these overhead accounts are related. Although not standard practice, O&M expenses may also be classified and allocated as the generating plants at which they are incurred are allocated.

VII. SUMMARY AND CONCLUSION

A. Choosing a Production Cost Allocation Method

As we have seen in the catalog of cost allocation methods above, the analyst chooses a method after considering many complex factors: (1) the utility's generation system planning and operation; (2) the cost of serving load with new generation or purchased power; (3) the incidence of new load on an annual, monthly and hourly basis; (4) the availability of load and operations data; and (5) the rate design objectives.

B. Data Needs and Sources

Most of the cost of service methods reviewed above require: (1) rate base data; (2) operations and maintenance expense data, depreciation expense data, and tax data; and (3) peak demand and energy consumption data for all rate classes. Some methods also require information from the utility's system planners regarding the operation of specific generating units and more general data such as generation mix, types of plants and the plant loading; for example, how often the units are operated, and whether they are run as baseload, intermediate or peaking units. Rate base, O&M, depreciation, tax and revenue data are generally available from the FERC Form 1 reports that follow the uniform system of accounts prescribed by FERC for utilities (18 CFR Chapter 1, Subchapter C, Part 101). See Chapter 3 for a complete discussion of revenue requirements. Load data may be gathered by the utility or borrowed from similar neighboring utilities if necessary. Data or information relating to specific generating units must be obtained from the utility's system planners and power-system operators.

C. Class Load Data

Any cost of service method that allocates part or all of production plant costs using a peak demand allocator requires at least estimates of the classes' peak demands. These may be estimates of the classes' coincident peak (CP) or non-coincident class peak (NCP) demands.

For larger utilities, class load data is generally developed from statistical samples of customers with time-recording demand and energy meters. Utilities without a load research program can sometimes borrow load data from others. See Appendix A for a thorough discussion of development of data through load research studies.

Different cost of service methods have different data requirements. The requirements may be as simple as: (1) total energy usage, adjusted for different line and transformation losses to be comparable at the generation level; (2) the class coincident peak demands in the peak hour of the year; and (3) the class non-coincident peak demands for the year. Some methods require much more complex data, ranging from class CP demands in each of the 12 monthly peak hours to estimated class demands in each hour of the year. Thus, load data development and analysis for cost of service studies entail substantial effort and cost.

D. System and Unit Dispatch Data

Some methods, such as the base-intermediate-peak methods, require classification of units according to their primary operating function. This may involve judgmental classification by system planners or power system operators. Other methods, such as the probability of dispatch methods, require either actual or modeled data regarding specific units' operation on an hour-by-hour basis, as well as hourly load data. Production stacking methods require data on the dispatch configuration of units, including reserves, required to serve a given load level. Such data must be developed and maintained by the utility.

E. Conclusion

This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

Schedule GAW-3

DUKE ENERGY KENTUCKY, INC.
Development of Base-Intermediate-Peak Generation Classification

Plant	2016 Net Generation MWH 1/	Capacity MW 2/	Capacity Factor 3/	Classification % 4/ Energy	Classification % 4/ Demand	Test Year Gross Plant 5/	Classification $ Energy	Classification $ Demand
East Bend	3,667,297	600	69.77%	69.77%	30.23%	$799,619,608	$557,922,867	$241,696,741
Woodsdale	31,659	564	0.64%	0.64%	99.36%	$319,573,334	$2,047,786	$317,525,548
Solar Facilities	--	6.8	21.60%	50.00%	50.00%	$14,573,894	$7,286,947	$7,286,947
TOTAL						$1,133,766,836	$567,257,600	$566,509,236
% Energy							50.03%	
% Demand								49.97%

1/ For East Bend and Woodsdale, per 2016 FERC Form 1 [FR 16(7)(k)].

2/ For East Bend and Woodsdale, per response to AG-DR-01-087. For solar, per Company Application in Case No. 2017-00155.

3/ For East Bend and Woodsdale, calculated per 2016 experience. For solar facilities, per Company Application in Case No. 2017-00155.

4/ Although the solar facilities' planning capacity factor is only 21.6%, Duke Energy Kentucky's peak demands invariably occur in a Summer month between the hours of 1:00 p.m. and 6:00 p.m. (per response to Staff-DR-2-004). As such, the solar facilities are expected to contribute to peak load requirements. Therefore, solar has been classified as 50%/energy and 50%/demand.

5/ Per response to AG-DR-01-086.

Schedule GAW-4

DUKE ENERGY KENTUCKY, INC.
Development of Peak & Average Allocation Factor

	TOTAL SYSTEM	RATE CLASS RS	DS	GSFL	EH	SP	DT-SEC	DT-PRI	DP	TT	LIGHTING	OTHER WATER PUMP
Class 1-CP Amount	847,000	340,781	285,348	1,123	0	67	112,642	74,087	2,959	29,963	0	30
Class 1-CP Pct.	100.0000%	40.2339%	33.6893%	0.1326%	0.0000%	0.0079%	13.2989%	8.7470%	0.3493%	3.5375%	0.0000%	0.0036%
Class KWH @ Gen Amount	4,196,163,573	1,508,499,412	1,170,225,895	6,457,090	19,810,437	277,908	708,045,264	514,497,482	16,235,892	232,190,426	19,741,342	182,425
Class KWH @ Gen Pct.	100.0000%	35.9495%	27.8880%	0.1539%	0.4721%	0.0066%	16.8736%	12.2611%	0.3869%	5.5334%	0.4705%	0.0043%
Development of P&A Allocator												
System Load Factor	56.5542%											
Energy Percent	56.5542%											
Demand Percent	43.4458%											
Energy Component	56.5542%	20.3309%	15.7718%	0.0870%	0.2670%	0.0037%	9.5427%	6.9342%	0.2188%	3.1294%	0.2661%	0.0025%
Demand Component	43.4458%	17.4799%	14.6366%	0.0576%	0.0000%	0.0034%	5.7778%	3.8002%	0.1518%	1.5369%	0.0000%	0.0016%
Total P&A	100.0000%	37.8109%	30.4084%	0.1446%	0.2670%	0.0072%	15.3206%	10.7344%	0.3706%	4.6663%	0.2661%	0.0040%

DUKE ENERGY KENTUCKY, INC.
Proposed Class Revenue Increases Per Company Revenue Proof
(Filing Schedule Series M)

	CURRENT REVENUES 1/			PROPOSED REVENUES 2/			PROPOSED INCREASE			PERCENT INCREASE		
RATE	TOTAL	RIDERS	BASE	TOTAL	RIDERS	BASE	TOTAL	RIDERS	BASE	TOTAL	RIDERS	BASE
RS	$131,689,037	$11,298,019	$120,391,018	$154,544,306	$11,298,019	$143,246,287	$22,855,269	$0	$22,855,269	17.36%		18.98%
DS	$92,357,164	$2,389,710	$89,967,454	$105,558,574	$2,389,710	$103,168,864	$13,201,410	$0	$13,201,410	14.29%		14.67%
GSFL	$603,277	$13,280	$589,997	$690,045	$13,280	$676,765	$86,768	$0	$86,768	14.38%		14.71%
EH	$644,536	$20,908	$623,628	$736,244	$20,908	$715,336	$91,708	$0	$91,708	14.23%		14.71%
SP	$29,301	$571	$28,730	$32,644	$571	$32,073	$3,343	$0	$3,343	11.41%		11.64%
DT-SEC	$47,381,524	$1,477,900	$45,903,624	$53,892,497	$1,477,900	$52,414,597	$6,510,973	$0	$6,510,973	13.74%		14.18%
DT-PRI	$31,781,792	$1,059,707	$30,722,085	$35,822,785	$1,059,707	$34,763,078	$4,040,993	$0	$4,040,993	12.71%		13.15%
DP	$954,503	$27,757	$926,746	$1,122,170	$27,757	$1,094,413	$167,667	$0	$167,667	17.57%		18.09%
TT	$13,157,767	-$62,744	$13,220,511	$14,623,146	-$62,744	$14,685,890	$1,465,379	$0	$1,465,379	11.14%		11.08%
LIGHTING	$1,880,402	-$8,961	$1,889,363	$2,103,105	-$8,961	$2,112,066	$222,703	$0	$222,703	11.84%		11.79%
OTHER-WATER PUMPING			$7,414			$7,414			$0			0.00%
TOTAL RATE REVENUE	$320,479,303	$16,216,147	$304,270,570	$369,125,516	$16,216,147	$352,916,783	$48,646,213	$0	$48,646,213	15.18%		15.99%

1/ Per Filing Schedule M-2.2, pages 2 through 20. Base revenues include fuel revenues consistent with Ziolkowski cost of service study.
2/ Per Filing Schedule M-2.3, pages 2 through 20. Base revenues include fuel revenues consistent with Ziolkowski cost of service study.

DUKE ENERGY KENTUCKY
Residential Customer Cost Analysis

		Including AMI Benefit	Excluding AMI Benefit
Gross Plant			
369	Services	$16,186,299	$16,186,299
370	Meters	$12,224,451	$12,224,451
	Total Gross Plant	**$28,410,750**	**$28,410,750**
Depreciation Reserve 1/			
	Services	$9,747,507	$9,747,507
	Meters	$461,024	$461,024
	Total Depreciation Reserve	**$10,208,531**	**$10,208,531**
Total Net Plant		**$18,202,219**	**$18,202,219**
Operation & Maintenance Expenses			
	Meters O&M	$189,512	$189,512
	Customer Accounting Expense	$1,732,762	$1,732,762
	Meter Reading	$233,172	$233,172
	AMI Benefit Levelization	-$1,206,086	--
	Total O & M Expenses	**$949,360**	**$2,155,446**
Depreciation Expense 1/			
	Services @ 2.07%	$334,760	$334,760
	Meters @ 7.65%	$934,909	$934,909
	Total Depreciation Expense	$1,269,669	$1,269,669
Revenue Requirement			
	Interest	$372,599	$372,599
	Equity return @ 10.30%	$916,660	$916,660
	State Income Taxes @ 5.345%	$79,634	$79,634
	Federal Income Tax @35.00%	$493,586	$493,586
	Revenue For Return	$1,862,480	$1,862,480
	O & M Expenses	$949,360	$2,155,446
	Depreciation Expense	$1,269,669	$1,269,669
	Subtotal Customer Revenue Requirement	$4,081,508	$5,287,594
	Total Revenue Requirement	**$4,081,508**	**$5,287,594**
	Number of Customers	126,269	126,269
	Number of Bills	1,515,228	1,515,228
	TOTAL MONTHLY CUSTOMER COST	$2.69	$3.49

1/ Per Filing Schedule B-3.2, page 4.