FILED
October 30, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	CAUSE NO. 45253

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

TESTIMONY OF

GLENN A. WATKINS – PUBLIC'S EXHIBIT NO. 13

OCTOBER 30, 2019

Respectfully submitted,

Scott Franson
Attorney No. 27839-49
Deputy Consumer Counselor

Public's Exhibit No. 13

STATE OF INDIANA

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VERIFIED DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

OCTOBER 30, 2019

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VERIFIED DIRECT TESTIMONY OF GLENN A. WATKINS
CAUSE NO. 45253
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

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 the Richmond, Virginia area. 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 39-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, Montana, Nevada, 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 Attachment GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("COMMISSION")?

A. Yes. I have provided testimony in Indiana Michigan Power's last two general rate cases (Cause Nos. 45235 and 44967), the two most recent Indianapolis Power & Light Company (Cause Nos. 44576 and 45029) and the two most recent Northern Indiana Public Service Company (Cause Nos. 44688 and 45159) rate cases.

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

A. Technical Associates has been engaged by the Office of Utility Consumer Counselor ("OUCC") to assist in its evaluation of the accuracy and reasonableness of Duke Energy Indiana's ("Duke" or "Company") forecasted energy sales and attendant revenues, retail class cost of service study, proposed distribution of revenues by class, and rate design as it relates to this rate application. The purpose of my testimony, 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 OUCC.

Q. ARE YOU SPONSORING ANY ATTACHMENTS WITH YOUR TESTIMONY?

A. Yes, I am sponsoring the filling attachments:

- Attachment GAW-1: Resume of Glenn A. Watkins;
- Attachment GAW-2: OUCC Residential KWH, Revenue and Margin Adjustment;
- Attachment GAW-3: Generation Plant Characteristics;
- Attachment GAW-4: Residential Customer Cost Analysis;
- Attachment GAW-5: Impact of OUCC KWH Adjustment to Residential Rate RS-General;
- Attachment GAW-6: Verified Statement of Jonathan Wallach
- Attachment GAW-7: Verified Statement of Glenn Watkins.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

A. While my investigation of Duke's forecasted test year (2020) level of energy sales and attendant revenues is incomplete due to a lack of data as well as inconsistencies in the Company's filing and workpapers, I have determined that Duke's forecasted Residential energy sales are significantly understated. As a result, I have adjusted Duke's forecasted amounts to reflect more a reasonable forecast for the Residential class. My adjustment affects both the Company's revenues at current rates as well as the billing determinants used for rate design purposes.

With regard to retail class cost of allocations, Duke has utilized the 4-CP method to allocate generation-related costs. While it is my opinion that the 4-CP method does not reasonably reflect cost causation, OUCC previously agreed not to oppose the 4-CP method in this case. However, the Company's class cost of service study utilizes the understated revenues for the Residential class that understates this class's rates of return at current rates.

With regard to the distribution of any overall decrease in base rate revenues authorized in this case to individual classes, I recommend that this decrease be spread across classes in inverse proportion to the Company's proposed class revenue increases. To the extent an overall increase is authorized for this case, I recommend that this increase be spread across rate schedules in proportion to the increases proposed by Duke.

With regard to Residential rate design, I recommend the Commission maintain the current level of Residential customer charges and accept Duke's structural changes to its current declining-block rate structure for Residential customers. Furthermore, I do not oppose Duke's proposed optional pilot for Residential and Small Commercial customers but recommend the Commission require Duke to collect and maintain data relating to customers' usages and billings under this experimental rate and provide periodic reports to interested parties.

Q. COULD YOU PLEASE DESCRIBE THE QUALITY OF DUKE'S COST OF SERVICE STUDY?

A. The information contained in Duke's filing was inadequate to conduct a proper investigation of its proposal, especially relating to its cost of service study. In my experience examining general rate case applications, I have always been able to review, examine and evaluate the information that the utility relied upon, as well as verify and understand how the raw data was manipulated or utilized within these studies, and able to replicate the utility's results. However, in this proceeding, Duke's cost of service study was not reasonably documented, did not provide much of the underlying information required to evaluate or fully understand its study, let alone verify the Company's results.

A description of the deficiencies in Duke's filings and the timeline on addressing these deficiencies were outlined in the Joint Motion to Amend Procedural Schedule filed by the OUCC, Citizen's Action Coalition of Indiana , and other intervenors on October 15, 2019, as well as the affidavits of Jonathan Wallach and me included with the filing, in which I stated that Duke's exhibits, workpapers and MSFRs are not documented, cross-referenced, or in any way linked to one another. Mr. Wallach's and my affidavits are included as Attachments GAW-6 and GAW-7, respectively. In the Joint Reply, filed on October 24, 2019, updated information was provided on further difficulties with Duke's filing and attempts to obtain additional information.

Q. DO YOU HAVE OTHER CONCERNS REGARDING DUKE'S PRESENTATION OF ITS COST OF SERVICE STUDY?

A. Yes. For reasons that are unclear and questions that OUCC has asked the Company but are yet unanswered, Duke has deemed every aspect of its CCOSS as confidential including the end results; i.e., rates of return by class. In my 39 years practicing public utility regulation involving hundreds of class cost of service studies, I have never seen the results of a CCOSS to be confidential. Indeed, the Company's CCOSS results are the foundation of its proposed class revenue requirements and rate design. In my opinion, the public has a right to know the basis upon which the Company has developed its proposed rates that its customers would be required to pay.

Q. HAVE YOU PARTICIPATED IN OTHER RATE CASES INVOLVING DUKE AFFILIATES?

A. Yes. I participated in a Duke Energy case in North Carolina before the North Carolina Public Utility Commission and in a 2018 case involving Duke Energy Kentucky before the Kentucky Public Service Commission. I am currently involved in a pending Duke Kentucky rate case before that Commission.

Q. HAVE YOU ENCOUNTERED THE SAME PROBLEMS IN THE OTHER DUKE PROCEEDINGS THAT YOU SEE IN THIS PROCEEDING?

A. No. The cost of service studies conducted and provided by Duke have all been fully transparent, reasonably documented, and not considered confidential. The differences between these proceedings in other States are almost night and day with regard to the quality and openness of the information provided in this case.

III. SALES AND REVENUE FORECAST

Q. DUKE IS PROPOSING TO USE A FULLY PROJECTED FUTURE TEST YEAR FOR RATEMAKING PURPOSES IN THIS CASE. HAVE YOU INVESTIGATED THE REASONABLENESS OF DUKE'S FORECASTED NUMBER OF CUSTOMERS, KWH SALES, AND RESULTING REVENUES?

A. To the best of my ability, yes. The deficiencies in the case-in-chief has made any investigation difficult. However, to the best of my ability given the limitations, I have investigated the reasonableness of the Company's forecasted Residential number of customers, KWH sales and attendant revenues. However, due to the lack of documentation, clarity, and errors provided in the Company's litany of unreferenced workpapers, and resulting time constraints, I have not been able to investigate the reasonableness of the Company's forecasted amounts for other classes; i.e., Commercial, Industrial, Other Public Authority, and Street Lighting.

Q. WHAT ARE YOUR FINDINGS REGARDING THE COMPANY'S FORECASTED NUMBER OF RESIDENTIAL CUSTOMERS, KWH SALES, AND ATTENDANT REVENUES?

A. As will be explained in detail below, the Company's forecasted KWH sales and attendant revenues for Residential customers used for ratemaking purposes (both for class cost of service purposes as well as actual rate design purposes) are significantly understated. With regard to the Company's forecasted number of Residential customers, I have found its forecast is within the range of reasonableness.

Q. HOW DID YOU DETERMINE THAT THE COMPANY'S RESIDENTIAL KWH SALES FORECAST IS SIGNIFICANTLY UNDERSTATED?

A. In order to understand my analysis, please refer to my Attachment GAW-2, page 2. The Company's KWH sales forecast is based on Duke's sales forecast prepared in the Fall of 2018 in which the Residential class MWH sales were forecasted to be 8,690,702 MWH. In this regard, and as can be seen in my Attachment GAW-2, the Company prepared an updated forecast in the Spring of 2019 (before its filing in this rate case) but elected to rely upon its prior Fall 2018 forecast for purposes of this case.

One can readily see in Attachment GAW-2 (page 2), the Company's Fall 2018 forecast is significantly lower than forecasted amounts for 2020, either in prior forecasts (Fall 2017 and 2016 forecasts), or in the more recent Spring 2019 forecast. Similarly, we can see that on a weather normalized basis, historical Residential sales during the period 2016 through 2018 have been significantly higher than the Company's forecasted Residential MWH sales used for ratemaking purposes in this case.

Q. HAVE YOU ADJUSTED THE COMPANY'S FORECASTED KWH SALES TO MORE REASONABLY REFLECT RESIDENTIAL CONSUMPTION DURING THE 2020 TEST YEAR?

A. Yes. In developing my forecasted Residential sales energy volumes (KWH), I have examined the trend in Residential weather normalized sales per customer over the most recent three-year period. As shown in the third panel of Attachment GAW-2 (page 2), we can see that the average weather normalized Residential KWH usages per customer have been 12,569 (CY 2016), 12,409 (CY 2017), and 12,513 (CY 2018). Given these reasonably consistent usages per customer over this three-year period, I have utilized an average of these amounts; i.e., 12,497 KWH per customer. I then multiplied this average per customer usage amount by the Company's Spring 2019 forecasted average number of Residential customers during 2020 of 738,993; i.e., average year 2020.

Q. WHY DID YOU RELY UPON THE COMPANY'S SPRING 2019 FORECAST FOR NUMBER OF CUSTOMERS?

A. As can be seen in the second panel of Attachment GAW-2 (page 2), as of August 2019 there were 732,118 Residential customers. I then compared the growth rate in Duke's Residential customers over the period 2016 through August 2019. As can be seen in this Attachment, Duke's Residential customers have been growing at an increasing rate over the last few years; i.e., 0.88% from 2016 to 2017, 1.44% from 2017 to 2018, and 1.62% annualized from 2018 to 2019.

Considering the actual number of Residential customers as of August 2019 was 732,118, when this amount is multiplied by the current (2019) annual growth rate of 1.62%, a Residential August 2020 customer count of 743,978 would result. Similarly, the average annual Residential customer growth rate over the 2016 through 2019 period has been 1.31%. When this annual growth rate is applied to the actual August 2019 number of customers (732,118) an August 2020 forecast of 741,733 would be obtained. In order to be conservative, I have accepted the Company's Spring 2019 forecast for the average number of customers during 2020 of 738,993.

Q. HOW DID YOU CALCULATE YOUR 2020 FORECASTED RESIDENTIAL KWH SALES?

A. As shown in the third panel of Attachment GAW-2 (page 2), I multiplied the three-year average weather normalized usage per customer of 12,497 KWH by the forecasted average year 2020 number of Residential customers of 738,993 to obtain a Residential sales forecast of 9,235,500 MWH.

Q. ARE THERE MULTIPLE SPECIFIC RATE SCHEDULES INCLUDED IN THE COMPANY'S AND YOUR FORECASTED RESIDENTIAL KWH SALES VOLUMES?

A. Yes. The Company's KWH sales forecast is made not on an individual rate schedule basis but rather on five general customer classifications that include: Residential; Commercial; Industrial; Other Public Authority; and, Street Lighting. Within what the Company defines as "Residential," there are multiple specific rate schedules. These rate schedules can be seen on page 1 of Attachment GAW-2. In order to develop revenues at current rates, Duke witness Jeffrey Bailey allocated the total "Residential" amounts to individual rate schedules as shown on page 1 of Attachment GAW-2.

I have utilized the same allocation to individual rate schedules as that used by Mr. Bailey. This enabled me to develop forecasted 2020 KWH sales by individual rate schedule.

Q. HOW DID YOU DEVELOP YOUR ADJUSTMENT TO RESIDENTIAL REVENUES AT CURRENT RATES?

A. I first calculated the weighted average base energy charges at current rates for each Residential rate schedule and multiplied these weighted average rates by my KWH sales adjustments as shown on page 1 of Attachment GAW-2. This produces a Residential base rate revenue adjustment of $31,919,717. In addition to the current base rate revenues, Duke proposes to move several riders into base rates for this case. Therefore, I calculated the current rate for those riders that are proposed to be moved into base rates of $0.045946 per

KWH.[1] This amount was then multiplied by my KWH adjustment of 544,798,635 to arrive at a tracker revenue adjustment of $25,031,335. Therefore, my total current revenue adjustment for the Residential class is $56,951,352.

Q. WITH ADDITIONAL SALES VOLUMES, WILL THE COMPANY INCUR ADDITIONAL EXPENSES?

A. Yes. By producing and selling more energy, the Company will incur additional fuel costs. As a result, I have determined that the Company's additional fuel cost will be $14,685,047 as shown on page 1 of Attachment GAW-2. This amount was developed by multiplying my sales adjustment of 544,798,635 KWH by the Company's proposed base cost of fuel of $0.026955 per KWH as set forth in the Company's Exhibit 5-F (SES).

When the additional revenues are netted against additional fuel costs, my analysis produces a before-tax margin adjustment of $42,266,005.

Q. EARLIER YOU INDICATED THAT THE COMPANY'S UNDERSTATEMENT OF RESIDENTIAL SALES AND REVENUES AFFECTS REVENUES AT CURRENT RATES AS WELL AS RESIDENTIAL RATE DESIGN. PLEASE EXPLAIN.

A. In developing specific rates by rate schedule, an individual rate is determined by dividing that rate schedule's revenue requirement by the amount of billing determinants. In the case

[1] It should be noted that during ongoing attempts to reconcile Mr. Bailey's revenue proofs by rate schedule to those contained in Company witness Douglas' revenue requirement, Mr. Bailey's tracker revenues at current rates do not match those utilized by Ms. Douglas. Finally, during a conference call on October 28, 2019, the Company informed OUCC that Mr. Bailey's revenue proof associated with tracker revenues is in error and the numbers used were based on preliminary numbers. Furthermore, the Company informed OUCC that the revenue amounts embedded in Ms. Douglas' workpapers are correct. Then, the Company informed OUCC that Ms. Douglas' total Company tracker revenues were simply allocated to individual rate classes and rate schedules. However, OUCC had spent numerous hours studying Ms. Douglas' undocumented workpapers and determined that her total tracker revenues are simply hard-keyed amounts and thus there was no way to verify or determine how the total Company tracker revenues were calculated. At the conclusion of this conference call, the Company agreed to provide such analysis to OUCC, however, at the time of writing this testimony such analysis have not been yet provided.

On a related topic, Mr. Bailey's Exhibit 8-B(JRB) shows each Residential tracker revenue at current rates. During the October 28, 2019 conference call, the Company indicated that the tracker rates shown in Mr. Bailey's Exhibit are correct and are based on forecasted 2020 amounts. However, when each Residential tracker proposed to move to base rates are added, the result is a total rate of $0.020470 per KWH. In contrast, Ms. Douglas' rider revenues that will be moving to base rates for Rate Schedules RSNO and RSN4 are $362,327,805. When this revenue amount is divided by the KWH sales utilized by both Ms. Douglas and Mr. Bailey of 7,885,943,587, the result is a tracker rate of $0.045946 per KWH. The exact same rate of $0.045946 per KWH is also obtained for Rate Schedule RSN2. Based on the Company's representation that Ms. Douglas' tracker revenues are correct (albeit unverifiable thus far), I have utilized Ms. Douglas' tracker rate for those riders moving to base rates.

of energy charges, if the revenue requirement remains constant but the amount of KWH billing determinants becomes larger, the calculated (and appropriate) energy charge rates become lower. This is most important because the ultimate outcome of this rate case is to establish fair and reasonable rates for individual rate schedules. I will further explain the rate design impact of my Residential sales adjustment later in the rate design section of my testimony.

IV. 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 tend to be allocated based on internally generated allocation factors, all allocation factors are ultimately a direct function of class contributions to: (a) demands ("kilowatt" or "KW"); (b) energy usage ("kilowatt-hour" or "KWH"); or, (c) number of customers. In this regard, energy usage and number of customers are readily known and measured from billing and financial records. However, class contributions to demands 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, such as Residential, must be estimated based on sample data since these class' meters only measure monthly energy, or 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. 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 the Federal Energy Regulatory Commission or "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.[2]

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. IS THERE A CERTAIN ASPECT OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TENDS TO BE MORE CONTROVERSIAL THAN OTHERS?

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

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[2] *Colorado Interstate Gas Co. V FPC*, 324 U.S. 581, 589 (1945).

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, production facilities 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 or 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 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, or KW, and the variable cost of producing a unit of energy 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 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 investment 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.[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:

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.

[3] Principles of Public Utility Rates, Second Edition, page 495, 1988.

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 had a peak load of 6,000 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 6,000 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 four highest monthly peak loads 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 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 or 4-CP 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.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities.

This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method, explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility's resources used to serve the varying 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.

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 units are evaluated on a case-by-case basis. This is because 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).

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. The OUCC agreed in a prior case not to oppose the use of the 4-CP for production plant in this case. Settlements involve give and take and I am not privy to why that was part of the settlement. Nonetheless, the agreement not to oppose does not change the flaws in the 4-CP methodology. Cost allocation methods that only consider peak loads (demands) such as the 1-CP and 4-CP 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 predominately comprised of nuclear and coal units installed coupled with run of the river hydro facilities that provide power throughout the year.

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 and 4-CP 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. Duke's generation portfolio is comprised of a variety of base load facilities as well as various intermediate and peaker units.

Q. CAN YOU EXPLAIN AND SHOW HOW DUKE'S PORTFOLIO OF GENERATING ASSETS ARE UTILIZED?

A. Yes. As shown in my Attachment GAW-3, the Company's base load plants produced about 95% of Duke's total owned generation energy (KWH) while its peaker plants only produced slightly more than 1% of the Company's total energy as they were only operated for a few hours of the year during peak load conditions. At the same time, when we evaluate the investments in Duke's portfolio of generation assets, we see that the vast majority (88%) of this investment is associated with base load generation that serves customers throughout the entire year. These relationships are particularly important and relevant in terms of cost causation as the Company's base load units are operated to serve load and energy requirements throughout the year while its peaker units are devoted to only serving peak load requirements.

When Duke's total generation investment costs are allocated to classes based only on a few peak hours of demand (e.g., the 4-CP method), the implicit assumption is that the Company's entire investment in generation plant is made to simply serve peak load requirements. However, as discussed above, this is clearly incorrect in that the vast majority (88%) of the Company's generation investment was made to serve customers' load and usage requirements throughout the year. Indeed, any allocation method that only considers a few hours of peak demand presents a significant bias against low load factor and weather sensitive customer classes such as the Residential class.

Q. WHAT COST ALLOCATION METHODOLOGY DOES DUKE UTILIZE TO ALLOCATE GENERATION PLANT COSTS WITHIN ITS PROPOSED CCOSS?

A. Duke witness Maria Diaz sponsors the Company's class cost of service studies. As indicated on page 6 of her revised direct testimony, Ms. Diaz conducted her studies utilizing both the 4-CP and 12-CP methods. In this regard, the 12-CP was utilized for informational purposes only in that the Company has relied upon its 4-CP study to evaluate class revenue responsibility. Furthermore, Ms. Diaz correctly notes that the OUCC agreed not to oppose the 4-CP methodology for production plant in this case based on a settlement reached in a prior proceeding (Cause No. 42873).

Q. DOES THE 4-CP METHOD REASONABLY REFLECT COST CAUSATION OF DUKE'S GENERATION PLANT AND RELATED COSTS ACROSS CLASSES?

A. No. As discussed earlier, the 4-CP only considers peak demands and does not consider the manner in which Duke's portfolio of generation assets were designed, built, or are utilized. However, in adhering to OUCC's prior commitment not to oppose the 4-CP method in this case, I have not conducted alternative CCOSS.

Q. WHAT IS THE COMPANY'S CALCULATED RESIDENTIAL ROR AT CURRENT RATES COMPARED TO THE SYSTEM AVERAGE ROR AT CURRENT RATES?

A. The Company's 4-CP CCOSS produces the following rates of return for the Residential class and the total Company.

TABLE 1
Duke 4-CP Residential and Total Retail ROR at Current Rates

Rate Schedule	Rate of Return	Relative ROR
Rate RS-General	1.85%	57%
Rate RS-High Efficiency	0.86%	26%
Total RS	1.76%	54%
Total Company Retail	3.27%	100%

Q. DOES THE COMPANY'S 4-CP CCOSS REFLECT ALL OF DUKE'S FORECASTED AND PROFORMA RATE BASE AND OPERATING INCOME AMOUNTS?

A. Yes.

Q. DO THE REVENUES IN THE COMPANY'S 4-CP CCOSS ALSO REFLECT DUKE'S FORECASTED RESIDENTIAL SALES REVENUES AT CURRENT RATES?

A. Yes.

Q. YOU HAVE DETERMINED THAT THE COMPANY'S FORECASTED REVENUES FOR THE RESIDENTIAL CLASS ARE SIGNIFICANTLY UNDERSTATED AND UNREASONABLE. HAVE YOU BEEN ABLE TO ESTIMATE THE RESIDENTIAL CLASS' RATE OF RETURN UTILIZING YOUR RECOMMENDED RESIDENTIAL REVENUES?

A. Yes. As discussed earlier, I have increased the Company's forecasted Residential revenues at current rates and variable fuel costs to arrive at a Residential before-tax margin increase of $42.266 million. While the following is not absolutely precise in that there are a few FERC accounts that are ultimately based on KWH volumes, the majority of costs allocated on a KWH basis relate to fuel costs. As such, the analysis that follows provides a reasonable estimate of the Residential class rate of return at current rates under the 4-CP method and incorporating my Residential revenue and fuel cost adjustment:

(1) Duke Residential NOI at Current Rates:	$84,780,388
(2) OUCC Before-Tax Margin Adjustment:	$42,266,005
(3) Revenue Conversion Factor:	1.34318
(4) OUCC NOI Adjustment (2) ÷ (3):	$31,467,119
(5) OUCC Revised Residential NOI (1) + (4):	$116,247,507
(6) Residential Rate Base:	$4,813,276,741
(7) OUCC Revised Residential ROR:	2.42%
(8) OUCC Revised Residential Relative ROR:	74%

V. CLASS REVENUE ALLOCATION

Q. WHAT METHOD DID THE COMPANY USE TO ALLOCATE ITS PROPOSED OVERALL $394.6 MILLION INCREASE TO INDIVIDUAL CLASSES?

A. Based on my examination of the Company's filing exhibits and workpapers, Duke's class revenue allocation method is based upon its 4-CP CCOSS results wherein each class's so-called "subsidy" or excess is calculated; i.e., the difference between calculated cost of service revenues and current revenues. Then, the Company proposes to reduce these so-called subsidies or excess by 5.1% for each class.

Q. WHAT ARE THE COMPANY'S PROPOSED REVENUE INCREASES FOR THE RESIDENTIAL CLASS?

A. The following table provides the Company's proposed Residential rate increases compared to the total Company proposed revenue increase:

TABLE 2
Duke Proposed Residential Revenue Increase

Rate	Current Rates: Base Rate Revenue a/	Current Rates: Trackers Moving To Base Rates b/	Current Rates: Total Current Revenue	Duke Proposed Revenue a/	Increase	% Increase	% of Average
RS - General	$544,189,847	$362,327,805	$906,517,652	$1,081,072,007	$174,554,355	19.26%	123%
RSN2 - HE	$45,195,160	$35,882,132	$81,077,292	$98,251,276	$17,173,984	21.18%	135%
Total Rate RS	$589,385,007	$398,209,937	$987,594,944	$1,179,323,283	$191,728,339	19.41%	124%
TOTAL DUKE RETAIL c/	Unknown	Unknown	$2,517,951,958	$2,912,522,000	$394,570,042	15.67%	100%

a/ Per Bailey Workpaper 1-5-16(a)(2) Workpaper 2_RS Rate Design Summary. Note: Excludes non-rate revenue for RS.
b/ Per Revised MSFR Workpaper REV2-DLD and response to Informal COSS Data Request 1.6-C.
c/ Per Petitioner's Exhibit 4-E (DLD). Note: Includes non-rate revenue.

Q. IS THE SO-CALLED RESIDENTIAL "SUBSIDY" SMALLER WITH THE INCORPORATION OF YOUR RESIDENTIAL REVENUE ADJUSTMENT?

A. Yes. Duke calculates the Residential so-called subsidy to be $72.470 million. However, as discussed earlier, my Residential revenue adjustment increases the Residential net operating income under the 4-CP method by $31.467 million thereby reducing this so-called subsidy by this same amount such that the adjusted Residential "subsidy" becomes $41.003 million.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSED INCREASE TO THE RESIDENTIAL CLASS?

A. Although no class cost of service study is surgically precise and therefore should only be used as one of the many tools in establishing class revenue responsibility, OUCC has agreed not to oppose the 4-CP method for purposes of this case. Furthermore, my revenue adjustment indicates that the so-called Residential revenue "subsidy" is significantly less than that portrayed by Duke. When all factors are considered, it is my opinion that the Company's proposed increase to the Residential class is reasonable under the Company's proposed overall revenue increase.

Q. OUCC WITNESS KOLLEN IS RECOMMENDING AN OVERALL REVENUE REDUCTION FOR THIS CASE. HOW SHOULD THIS REDUCTION TO CURRENT REVENUES BE ALLOCATED ACROSS CLASSES?

A. I recommend that any overall reduction to the Company's overall revenue requirement be allocated to classes in inverse proportion to the Company's proposed increases. In other words, those classes that receive smaller increases would receive larger decreases while those classes that receive larger increases would receive smaller decreases. These decreases would be in inverse proportion by class.

Q. TO THE EXTENT THE COMMISSION AUTHORIZES AN OVERALL INCREASE LESS THAN THAT REQUESTED BY DUKE, HOW SHOULD THE OVERALL INCREASE BY ALLOCATED ACROSS CLASSES?

A. I recommend that any reduction in the authorized overall increase be scaled-back proportionately based on the Company's proposed class revenue allocation.

VI. <u>RESIDENTIAL RATE DESIGN</u>

Q. PLEASE EXPLAIN THE COMPANY'S CURRENT RESIDENTIAL RATE STRUCTURES.

A. Duke offers two separate rate schedules for traditional Residential customers: Rate RS-General and Rate RS-High Efficiency. With regard to Rate RS-General (the rate under which the vast majority of Residential customers take service), the fixed monthly customer charge is currently $9.01. With respect to existing energy charges, there is a three-tiered severely declining-block rate structure wherein the first usage block is priced at $0.089116, the second usage block ($0.051948) is priced 41.7% lower than the first usage block, and the third usage block ($0.042634) is priced 52.2% lower than the first usage block. In addition, Residential customers are subject to 12 separate riders.

With regard to Rate RS-High Efficiency, this rate schedule is closed to new customers as well as closed to existing Rate RS-General customers that would otherwise desire this rate schedule. The fixed monthly charge is also $9.01 per month. This rate schedule also utilizes a three-tiered severely declining-block rate structure with the same energy rates as Rate RS-General for the Summer months (July through October) but provides for an even larger discount in the third usage block during the non-Summer months (November through June). For Rate RS-High Efficiency, the non-Summer third block of $0.036235 is priced 59.3% lower than the first usage block.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RATE RS-GENERAL RATES AND RATE STRUCTURE.

A. As set forth in the revised direct testimony of Company witness Bailey, Duke proposes two rate design options relating to Rate RS-General. The Company's first, and preferred option, is if Duke is allowed to implement decoupling in this case; its second option is without decoupling. The following tables presents Duke's proposed Rate RS-General under both options:

TABLE 3
Rate RS-General
Duke Proposed Rate Design w/ Decoupling

Description	Rate	Percent Reduction To 1st Usage Block
Customer Charge	$9.80	
Energy Charges:		
1st Block (0-300)	$0.150893	--
2nd Block (301-1,000)	$0.122344	18.9%
3rd Block (>1,000)	$0.110347	26.9%

TABLE 4
Rate RS-General
Duke Proposed Rate Design w/o Decoupling

Description	Rate	Percent Reduction To 1st Usage Block
Customer Charge	$10.54	
Energy Charges:		
1st Block (0-300)	$0.160859	--
2nd Block (301-1,000)	$0.117074	27.2%
3rd Block (>1,000)	$0.106102	34.0%

Q. WHAT RATIONALE DOES THE COMPANY PROVIDE FOR ITS PROPOSED FIXED MONTHLY CUSTOMER CHARGES OF $9.80 WITH DECOUPLING OR $10.54 WITHOUT DECOUPLING?

A. In his Exhibit 8-D (JRB), Mr. Bailey indicates that his calculated Residential customer cost is $9.80 per month. Although the Company has not provided any information as to exactly which FERC accounts are included in this calculation (or how this amount was calculated), Mr. Bailey states on page 6 of his revised direct testimony that this amount includes customer accounts, customer service and information, allocated general and intangible rate base and "certain expenses including billing, bad debts, and customer service."

With regard to the Company's proposed $10.54 per month Residential customer charge if decoupling is not approved, I have no idea how Mr. Bailey developed this amount. Mr. Bailey provides no calculation or explanation as to the elements of the customer charge or how the increase was determined. However, Mr. Bailey does state in his revised direct testimony that his rate design without decoupling presents "a modest reduction in risk to the Company." With this statement, I interpret Mr. Bailey's intention under the rate design option without decoupling to simply reduce risk to the Company because fixed customer charges represent guaranteed revenue recovery and that a more severe declining-block rate also reduces primarily weather-related risk to the Company.[4]

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 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 an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

[4] The majority of Residential usage in the third rate block occurs during the Winter and Summer months wherein weather in a given month is the primary determinant of usage in the third block.

Under this direct customer cost approach, there is no provision to include corporate overhead expenses or any other indirect costs in the customer charge. As explained below, these costs are more appropriately recovered through energy (KWH) charges.

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

A. Yes. I conducted a direct customer cost analysis of Duke's Residential class. The details of this analysis are provided in my Attachment GAW-4. As indicated in this Attachment, the Residential direct customer cost is calculated to be between $8.59 and $8.87 per month. The lower cost of $8.59 is based on a 9.0% return on equity as recommended by OUCC witness David Garrett, while the higher cost of $8.87 is based on the Company's requested return on equity of 10.40%. In this regard, a cost of equity of even 9.0% overstates the risks associated with fixed monthly customer charges. This is because customer charges are "fixed" charges such that Residential customers must pay this charge every month, even with no energy usage, and there is virtually no risk associated with this charge.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS SUCH AS GENERAL AND INTANGIBLE RATE BASE AS WELL AS ALL BAD DEBT EXPENSES IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all electric utilities, Duke is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to Duke's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT ARE YOUR RECOMMENDATIONS REGARDING RESIDENTIAL RATE DESIGN FOR THIS CASE?

A. Although my customer cost analysis indicates that a customer charge of no more than $8.59 is warranted, I recommend that the current Residential monthly customer charges of $9.01 for both Rate RS-General and Rate RS-High Efficiency be maintained at their current levels. Maintaining the current Residential customer charges will promote rate continuity as well as encouraging conservation as any increase authorized in this case will be collected from the Residential energy charges, thereby sending a more appropriate price signal for customers to conserve and use energy more efficiently. As a very slight adjustment, a customer charge of $9.00 plus $0.01 makes little sense and I suggest that an even $9.00 per month Residential customer charge is more appropriate.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO MAINTAIN ITS DECLINING-BLOCK ENERGY CHARGES FOR THE RESIDENTIAL CLASS.

A. As discussed earlier, Duke's current Residential energy charges consist of a three-tiered severely declining-block rate structure. In this regard, Mr. Bailey acknowledges on pages 4 and 5 of his revised direct testimony that the magnitude of the declining-block rates "would be difficult to justify today." As a result, Mr. Bailey does recommend reducing the discount in the second and third usage blocks under both of his rate design options (with and without decoupling). In my opinion, this is a step in the right direction in that declining-block rate structures were originally developed as a promotional tool to encourage additional electricity consumption. However, in this day of conservation consciousness, such promotional rate designs have been discouraged and found to be contrary to public policy conservation efforts.

Q. WHAT IS YOUR OPINION REGARDING MR. BAILEY'S TWO SEPARATE RESIDENTIAL RATE DESIGN OPTIONS WITH AND WITHOUT REVENUE DECOUPLING?

A. As stated earlier, Mr. Bailey's proposed rate design without decoupling was developed simply to reduce the Company's risk. While I agree that higher customer charges coupled with more precipitous declining-block energy rates does indeed reduce the Company's risk, this should not be a driving factor for reasonable rate design.

Q. EARLIER YOU INDICATED THAT THE COMPANY'S UNDERSTATEMENT OF FORECASTED RESIDENTIAL KWH ENERGY SALES AFFECTS THE RATE DESIGN FOR THE RESIDENTIAL CLASS. HAVE YOU PREPARED AN ATTACHMENT TO SHOW THE RATE DESIGN IMPACT OF YOUR KWH SALES ADJUSTMENT.

A. Yes. My Attachment GAW-5, which consists of two pages, shows the rate design impact on the Residential Rate RS-General schedule. Page 1 of this Attachment shows the impact on energy charge rates utilizing the Company's proposed customer charge of $9.80 per month and using the Company's Residential revenue requirement. Page 2 of this Attachment shows the impact on energy charge rates utilizing my recommended customer charge of $9.01 per month and using the Company's Residential revenue requirement.

As shown on both pages 1 and 2 of Attachment GAW-5, the energy rates are lower with the incorporation of my KWH sales adjustment simply due to the fact that there are more KWH billing determinants to collect this rate schedule's revenue requirement.

Q. HAVE YOU CALCULATED THE BILL IMPACT OF YOUR SALES ADJUSTMENT FOR A TYPICAL RESIDENTIAL CUSTOMER?

A. Yes. For a typical Rate RS-General customer using 1,000 KWH per month, the bill impact utilizing the Company's proposed $9.80 monthly customer charge is $7.72 per month while the bill impact utilizing my recommended $9.01 monthly customer charge is $7.68 per month. That is, by reflecting a more appropriate level of forecasted KWH sales, this typical customer's bill would be about $7.70 lower per month.

Q. DO YOU HAVE ANY COMMENTS OR RECOMMENDATIONS RELATING TO THE COMPANY'S PROPOSED OPTIONAL RESIDENTIAL AND SMALL COMMERCIAL PILOT RATES?

A. Yes. Duke is proposing a pilot program to utilize dynamic pricing that will be available to those customers with Smart Meters. Mr. Bailey discusses these optional pilot rates on pages 15 through 21 of his revised direct testimony. Because these proposed rate schedules are optional in that they will provide customers with another service alternative, I do not object to this proposed pilot rate. However, the purpose of every pilot, or experimental, program is to gather and obtain information. As such, if the pilot is approved, I recommend the Commission direct Duke to keep and maintain specific records on a customer by customer basis that compares each customer's actual bills (and billing determinants) to those that would have resulted under Rate RS. Furthermore, the Company should be required to submit detailed reports, data, and workpapers to the Commission, OUCC, and other interested parties on at least an annual basis concerning customer impacts and changes and in energy usage and peak load as a result of the critical peak pricing structure.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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. Public Utility Regulation

A. Costing Studies -- 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. Rate Design Studies -- 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.

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IV. Anti-Trust and Commercial Business Damage Litigation

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

DUKE ENERGY INDIANA
OUCC Residential KWH, Revenue and Margin Adjustment

3-Year Average Weather Normalized Residential Usage Per Customer (KWH) 1/	**12,497**
Duke Forecasted 2020 Average Year No. of Residential Customers (Spring '19 Forecast) 1/	**738,993**
OUCC Forecasted 2020 Residential KWH Sales 1/	**9,235,500,317**

Allocate to Rate Codes:

Residential Code	Residential Name	Duke KWH Forecast Allocated Amount 2/	Duke KWH Forecast Allocation Percent	OUCC KWH Forecast Allocated Amount 3/	OUCC KWH Forecast Sales Adjustment	Weighted Average Base Energy Charge 4/	OUCC Base Revenue Adjustment
LSNO	GS - LLF No Meter Adj.	4,656,817	0.0536%	4,948,741	291,924	$0.056486	$16,490
LSN4	Farm - LLF	3,164,305	0.0364%	3,362,667	198,362	$0.056486	$11,205
RSNO	RS - General	7,848,601,252	90.3103%	8,340,610,690	492,009,438	$0.059290	$29,171,396
RSN2	RS - High Efficiency	780,912,177	8.9856%	829,865,634	48,953,457	$0.051916	$2,541,486
RSN4	RS - Farm Service	33,630,605	0.3870%	35,738,825	2,108,220	$0.059290	$124,997
SMLC	Metered OL - Company Owned	1,629	0.0000%	1,731	102	$0.031568	$0
SMLP	Metered OL - Customer Owned	6,652	0.0001%	7,069	417	$0.031568	$13
UOLS	Unmetered OL	19,728,245	0.2270%	20,964,960	1,236,715	$0.043770	$54,131
Total Residential		8,690,701,682	100.0000%	9,235,500,317	544,798,635	--	$31,919,717

OUCC Base Rate Revenue Adjustment	$31,919,717	
Residential Riders Moving to Base Rates	$0.045946	5/
OUCC Tracker Revenue Adjustment	$25,031,335	
OUCC Total Revenue Adjustment	**$56,951,052**	
Fuel Cost per KWH	$0.026955	6/
OUCC Fuel Cost Adjustment	$14,685,047	
OUCC Margin Adjustment	**$42,266,005**	

1/ Per Page 2.
2/ Per 45253 DEI Workpaper 6-JRB 071019.xls, Tab: Rate Calc Sheet and 10/21/19 Affidavit of Jeffrey Bailey.
3/ Total Residential per Page 2 and allocated to rate schedules per Duke allocation percentages.
4/ Calculated per Bailey Workpapers [1-5-16(a)(2)].
5/ Calculated per Douglas Revised MSFR Workpaper REV2-DLD [1-5-8(a)(2)], Column F (Tracker Revenue Moving to Base Rates) divided by forecasted KWH per Bailey Rate Design [1-5-16(a)(2)] (Workpaper 2_RS Rate Design Summary.xlsm) and also Duke response to CAC 12.7-C.
6/ Per Petitioner's Exhibit 5-F(SES) and response to Informal COSS Data Request 1.6-D.

DUKE ENERGY INDIANA
OUCC Residential 2020 MWH Forecast

I. Residential MWH Sales

Forecast	2016	2017	2018	2019	2020		2021	YTD Aug. 2019	
Spring- 19 1/				9,040,555	9,051,878		9,069,214	6,269,458	
Fall - 18 1/				8,767,201	8,690,702		8,684,328	6,079,090	
Fall - 17 1/			8,912,069	8,945,246	8,999,658		9,027,839	6,268,904	
Fall - 16 1/		8,842,896	8,956,582	8,986,150	9,049,001		9,059,245	6,318,274	
Actual 2/	8,917,714	8,574,832	9,648,621					6,347,489	
Weather Normalized 2/	8,896,439	8,860,619	9,063,096					6,247,745	
Claimed Rate Case MWH					**8,690,702**	3/		6,014,621	4/

II. Number of Residential Customers EOY

Forecast	2016	2017	2018	2019	2020	2021	YTD Aug. 2019
Spring- 19 1/				735,765	742,220	748,109	726,442
Fall - 18 1/				733,045	737,796	743,877	722,249
Fall - 17 1/			727,573	733,324	738,829	743,988	720,557
Fall - 16 1/		716,830	720,212	724,158	728,018	731,468	710,702
Actual 2/	707,782	714,024	724,272				732,118
Annual Growth Rate		0.88%	1.44%	1.62%			
				Actual YTD Annualized to Year End			
Annualized Amount				736,041			

III. OUCC Forecasted 2020 Residential KWH Sales

	2016	2017	2018	2020	
Avg KWH Use/Cust Weather Normalized	12,569	12,409	12,513		
3-Year Average Weather Normalized Use Per Customer				12,497	
2020 Avg. Yr. No. of Cust. Based on Spring '19 Forecast				738,993	
OUCC KWH Forecast					**9,235,500,317**

1/ Per response to OUCC 4.1 attach A
2/ Per response to OUCC 4.1 attach C
3/ Per 45253 DEI Workpaper 6-JRB 071019.xls, Tab: Rate Calc Sheet and 10/21/19 Affidavit of Jeffrey Bailey.
4/ Per 45253 DEI Workpaper 6-JRB 071019.xls, Tab: Rate Calc Sheet.

DUKE ENERGY INDIANA
Generation Plant Characteristics

	Plant	Nameplate Capacity (MW)	Net Generation KWH	Net Generation % of Total	Total Cost $	Total Cost % of Total	Fuel Cost	Capacity Factor	Installed Cost Per KW	Fuel Cost Per KWH
Base Load	Cayuga	1,062	5,922,853,336	20.58%	1,577,717,537	16.89%	$ 145,590,321	63.7%	$ 1,486	$ 0.0246
	Noblesville	283	1,506,408,000	5.23%	263,657,519	2.82%	$ 39,135,299	60.8%	$ 932	$ 0.0260
	Gibson	3,006	15,937,485,000	55.37%	3,654,126,563	39.13%	$ 341,883,869	60.5%	$ 1,216	$ 0.0215
	Edwardsport IGCC	805	3,962,017,000	13.76%	2,711,641,162	29.04%	$ 108,040,770	56.2%	$ 3,371	$ 0.0273
	Total Base Load	**5,156**	**27,328,763,336**	94.95%	**8,207,142,781**	87.88%	**634,650,259**	**60.5%**	**$ 1,592**	**$ 0.0232**
Intermediate	Cadiz (Henry County)	182	283,650,000	0.99%	88,428,408	0.95%	$ 10,017,234	17.8%	$ 487	$ 0.0353
	Gallagher	300	285,152,000	0.99%	441,219,186	4.72%	$ 12,710,573	10.9%	$ 1,471	$ 0.0446
	Madison	692	541,948,000	1.88%	334,051,154	3.58%	$ 27,456,755	8.9%	$ 483	$ 0.0507
	Total Intermediate	**1,174**	**1,110,750,000**	3.86%	**863,698,748**	9.25%	**50,184,562**	**10.8%**	**$ 736**	**$ 0.0452**
Peaking	Wheatland	500	191,791,000	0.67%	109,801,445	1.18%	$ 9,598,467	4.4%	$ 219	$ 0.0500
	Vermillion	433	151,998,000	0.53%	155,348,430	1.66%	$ 7,507,671	4.0%	$ 359	$ 0.0494
	Cayuga Peaking	10	290,000	0.00%	2,792,527	0.03%	$ 49,493	0.3%	$ 269	$ 0.1707
	Total Peaking	**943**	**344,079,000**	1.20%	**267,942,402**	2.87%	**17,155,631**	**4.2%**	**$ 284**	**$ 0.0499**
Total		**7,272**	**28,783,592,336**	100.00%	**9,338,783,931**	100.00%	**701,990,452**			
Other	Wabash River	473	-		-		$ -	0.0%	$ -	$ -
	Miami Wabash	87	(33,000)		-		$ -	0.0%	$ -	$ -
	Connersville	84	(108,000)		-		$ -	0.0%	$ -	$ -
	Cayuga CT	113	(157,000)		53,107,158		$ 29,842	0.0%	$ 472	$ -
	Total Other	**756**								

Source: FERC Form 1, 2018.

DUKE ENERGY INDIANA
Residential Customer Cost Analysis

		Duke Proposed ROE		OUCC Proposed ROE	
		RSNO	**RSN2**	**RSNO**	**RSN2**
Gross Plant					
369	Services	$257,019,641	$15,733,814	$257,019,641	$15,733,814
370	Meters	$87,179,406	$5,336,809	$87,179,406	$5,336,809
	Total Gross Plant	$344,199,047	$21,070,623	$344,199,047	$21,070,623
Depreciation Reserve					
	Services	-$154,459,231	-$9,455,437	-$154,459,231	-$9,455,437
	Meters	-$18,288,689	-$1,119,568	-$18,288,689	-$1,119,568
	Total Depreciation Reserve	-$172,747,920	-$10,575,005	-$172,747,920	-$10,575,005
Total Net Plant		$171,451,127	$10,495,618	$171,451,127	$10,495,618
Operation & Maintenance Expenses					
586	Dist Oper - Meter	$3,878,096	$237,403	$3,878,096	$237,403
587	Customer Installations	$21,469,342	$1,314,276	$21,469,342	$1,314,276
902	Meter Reading	-$46,921	-$2,872	-$46,921	-$2,872
903	Customer Records	$19,749,615	$1,209,000	$19,749,615	$1,209,000
	Total O & M Expenses	$45,050,132	$2,757,807	$45,050,132	$2,757,807
Depreciation Expense					
	Services	$4,675,264	$286,203	$4,675,264	$286,203
	Meters	$5,730,706	$350,813	$5,730,706	$350,813
	Total Depreciation Expense	$10,405,970	$637,016	$10,405,970	$637,016
Revenue Requirement					
	Interest	$3,926,231	$240,350	$3,994,811	$244,548
	Equity return	$9,457,518	$578,955	$7,715,301	$472,303
	State Income Taxes	$537,217	$32,886	$438,254	$26,828
	Federal Income Tax	$2,371,219	$145,157	$1,934,405	$118,417
	Revenue For Return	$16,292,186	$997,349	$14,082,770	$862,096
	O & M Expenses	$45,050,132	$2,757,807	$45,050,132	$2,757,807
	Depreciation Expense	$10,405,970	$637,016	$10,405,970	$637,016
	Subtotal Customer Revenue Requirement	$71,748,288	$4,392,172	$69,538,872	$4,256,919
	Total Revenue Requirement	$71,748,288	$4,392,172	$69,538,872	$4,256,919
	Number of Bills	8,126,256	497,460	8,126,256	497,460
	Monthly Cost Before Bad Debts & Utility Receipts Tax	$8.83	$8.83	$8.56	$8.56
	Bad Debts + Public Utility Fee	0.4087%	0.4087%	0.4087%	0.4087%
	TOTAL MONTHLY CUSTOMER COST	**$8.87**	**$8.87**	**$8.59**	**$8.59**

DUKE ENERGY INDIANA
Impact of OUCC KWH Adjustment to Residential Rate RS-General 1/
Based on Duke Proposed Customer Charge

Description			Duke Forecasted Sales: Customer Bills and KWH	Duke Forecasted Sales: 2020 Pro Forma Rate	Duke Forecasted Sales: Annualized Revenue at Pro Forma 2020 Rates	OUCC Forecasted Sales: Customer Bills and KWH	OUCC Forecasted Sales: 2020 Pro Forma Rate	OUCC Forecasted Sales: Annualized Revenue at Pro Forma 2020 Rates
Customer Bills			8,510,599	$ 9.80	$ 83,402,737	8,510,599	$ 9.80	$ 83,402,737
Energy	Begin	End						
1st Block	0	300	2,152,932,276	$ 0.150893	$ 324,861,714	2,287,830,763	$ 0.141996	$ 324,861,714
2nd Block	301	1000	3,358,190,351	$ 0.122344	$ 410,854,848	3,568,607,929	$ 0.115130	$ 410,854,848
3rd Block	1001	1000	-	$ 0.110347	$ -	-		$ -
4th Block	1001	1000	-	$ 0.110347	$ -	-		$ -
End Block	1001	and Over	2,374,820,960	$ 0.110347	$ 262,053,531	2,523,622,553	$ 0.103840	$ 262,053,531
Total Energy			7,885,943,587		$ 997,770,093	8,380,061,245		997,770,093
Calculated Revenue					$ 1,081,172,830			1,081,172,830
Correction Factor					0.999906747			0.999906747
Total Proforma Revenue before Other Adjustments					$ 1,081,072,007			$ 1,081,072,007

1/ Includes Rate codes RSNO and RSN4.

DUKE ENERGY INDIANA
Impact of OUCC KWH Adjustment to Residential Rate RS-General 1/
Based on Maintaining the Current Customer Charge

			Duke Forecasted Sales			OUCC Forecasted Sales		
Description			Customer Bills and KWH	2020 Pro Forma Rate	Annualized Revenue at Pro Forma 2020 Rates	Customer Bills and KWH	2020 Pro Forma Rate	Annualized Revenue at Pro Forma 2020 Rates
Customer Bills			8,510,599	$ 9.80	$ 83,402,737	8,510,599	$ 9.01	$ 76,680,497
Energy	Begin	End						
1st Block	0	300	2,152,932,276	$ 0.150893	$ 324,861,714	2,287,830,763	$ 0.142952	$ 327,050,393
2nd Block	301	1000	3,358,190,351	$ 0.122344	$ 410,854,848	3,568,607,929	$ 0.115906	$ 413,622,886
3rd Block	1001	1000	-	$ 0.110347	$ -	-		$ -
4th Block	1001	1000	-	$ 0.110347	$ -	-		$ -
End Block	1001	and Over	2,374,820,960	$ 0.110347	$ 262,053,531	2,523,622,553	$ 0.104540	$ 263,819,055
Total Energy			7,885,943,587		$ 997,770,093	8,380,061,245		1,004,492,333
Calculated Revenue					$ 1,081,172,830			1,081,172,830
Correction Factor					0.999906747			0.999906747
Total Proforma Revenue before Other Adjustments					$ 1,081,072,007			$ 1,081,072,007

1/ Includes Rate codes RSNO and RSN4.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED STATEMENT OF JONATHAN WALLACH

1. My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

2. I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

3. Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

4. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility Regulatory Commission (“the Commission”) in Cause Nos. 44967, 45029, 45159, and 45235.

5. I have testified in more than 30 general rate cases across the nation, including in Duke Energy’s most recent general rate cases in North and South Carolina.

6. I have reviewed Duke Energy Indiana's ("Duke" or the "Company") pre-filed testimony in Cause No. 45253 and have reviewed the primary results of Citizens Action Coalition's ("CAC") discovery on the Company in Cause No. 45253 to date. I have participated in several phone calls with the Company throughout September and October, attempting to find critical information for my case-in-chief filing that has been extremely burdensome and time-consuming for my team at Resource Insight and me to find ourselves.

7. During my review of Duke's case-in-chief testimony, workpapers, MSFRs, and exhibits in late-August of 2019, I discovered that the presented Cost of Service Study ("COSS") workpaper did not actually functionalize, classify, and allocate test-year costs. In other words, Confidential Workpaper 2-MTD, sheet RC ALOCC, does not have any formulas or other critical pieces of information, just 69,000+ rows of output data from the Company's proprietary COSS software model pasted in. I notified CAC's counsel so she could request Duke to provide a copy of the COSS that would allow me to review the necessary information to perform my analysis for my case-in-chief submission.

8. On September 19, 2019, I attended a call with various Duke representatives and other consumer parties interested in the COSS to discuss how parties were having difficulty finding critical information that should be located in the MSFRs, workpapers, and exhibits and how best to rectify the situation. Duke provided a preview of their proprietary model via Skype and received multiple questions from expert witnesses as it became clear that this presentation did not show how this new model performed the functionalization, classification, and allocation of costs as a traditional spreadsheet-based COSS model would. It also became clear that Duke had not provided a clear statement or chain of evidence in terms of which information was being fed into the model or calculated within the model and provided as an output somewhere in the Company's MSFRs or workpapers. Experts asked several questions with regard to how this new model actually worked and where experts could figure out whether critical information was fed into, represented in, and/or coming out of the model. Experts also asked several questions with regard to where they could find certain information and supporting information that had been difficult to locate on their own. For example, experts asked questions and voiced concerns about how the load data is fed into or calculated in the model, how external allocators were developed, and where to find the loss factors. I found it concerning that the Duke representatives themselves were struggling with where to find certain information. They also admitted that certain information, like detailed O&M expenses by FERC account, were rolled up into summarized information as an output from Duke's proprietary COSS software model and had not been provided at the detailed level in their case-in-chief submission. They further confirmed our concerns that their chain of evidence was broken between various spreadsheets at issue in this case, meaning that with the information provided, when Duke reaches a result in one spreadsheet, it merely copies those numbers and pastes them into the next spreadsheet, not linking the spreadsheets in any way or even leaving a citation trail so that parties could reasonably find where the next logical chain of evidence would be. In my experience, Commissions have required and utilities have presented information with a clear and transparent chain of information with spreadsheets linked between each other.

On the call, Duke agreed to put forth some spreadsheets with formulae intact for experts and counsel to review and discuss with Duke the following week.

9. On September 23, 2019, Duke provided an Excel-based replica of the COSS software model via email broken into two separate Excel workbooks (Class and Functional Allocation workbooks).

10. On September 25, 2019, I participated in another phone/Skype call with Duke and various other consumer representatives interested in the COSS issues. On this call, certain parties pointed out several deficiencies in these two Excel workbooks, and Duke agreed to attempt to correct those and supplement it with a new version of the Excel based replica of the COSS model. One major deficiency CAC asked Duke to address was the fact that the allocation factors had been copied as values from various undocumented MSFRs and workpapers, making it impossible for the parties to follow the chain of evidence regarding the derivation of those allocation factors. Duke later provided a key attempting to address this deficiency, which has been helpful, but has not come close to addressing the problem. Another concern voiced on this call was whether Duke would agree to make specifically requested changes to the COSS model for parties for purposes of their analysis—a standard discovery function in my experience and an elevated concern here considering Duke's reliance on a new model. Duke also admitted on this call that they had created an earlier version of this Excel-based replica of the COSS model to verify the proprietary model results, yet they just made it available to parties on September 23, 2019.

11. On September 30, 2019, Duke provided parties with a second version of the Excel-based replica of the COSS model via email. In this new version, Duke combined the Class and Functional Allocation files into one file, simplified the mapping from the Function Allocation sheets to the COSS, added an Adjustment column to the Function Allocation sheets, grouped the Input sheets into one section, added Net Operating Income and Rate Increase workpapers COSS16-26, added an "Impact of Changes" sheet to compare the results from any changes made in this file to amounts filed in the rate case, and added a second level reference to the allocation factor input sheets.

12. Throughout the week of September 30, 2019, I worked to gather a more comprehensive list of deficiencies and outstanding issues to again bring to Duke along with a proposal for a request for extension to the current procedural schedule. It is my understanding that Duke rejected our request to refile the MSFRs, workpapers, and exhibits so as to improve the documentation, cross-referencing, and linkage between these spreadsheets, which has and will continue to significantly impair my ability to complete my analysis at all, but especially for an October 30, 2019 due date. It is also my understanding that Duke rejected our request for a three-week extension, despite our stated concern that we spent over a month working to try and figure out the COSS issue.

13. In my experience, I have never seen a rate filing that compares to this in terms of the unsupported, inadequate, unorganized, and undocumented presentation of evidence. I can attest to the fact that these issues did not exist in the most recent Duke Energy Carolinas rate case, Docket No. 2018-319-E before the South Carolina Public Utilities Commission.

14. I affirm, under the penalties of perjury, that the foregoing statements are based on personal knowledge and are true and correct to the best of my knowledge, information and belief.

Further I say not.

Jonathan F. Wallach
October 11, 2019

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED STATEMENT OF GLENN WATKINS

1. My name is Glenn A. Watkins. I am President and Senior Economist with Technical Associates, Inc., 6377 Mattawan Trail, Mechanicsville, Virginia 23116.
2. I have worked as a consultant to the utility industry since 1980. During my career 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.
3. I have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I have provided expert testimony before State and Federal courts as well as before State legislatures.
4. I have testified in numerous general rate cases across the country including Duke Energy's most recent general rate case in Kentucky (2018), a Duke Energy rate case in North Carolina (2009) and am currently engaged in the pending Duke Energy of Kentucky general rate case.
5. I have reviewed Duke Energy Indiana's ("Duke") pre-filed testimony in Cause No. 45253 and have issued and reviewed pertinent discovery responses to date. I have participated in several phone calls with Duke throughout September and October, attempting to ascertain critical information for my review and preparation of my direct testimony. Throughout this case, it has been extremely burdensome and time-consuming for me and my team at Technical Associates to locate critical information.

6. Duke's rate filing reflects a forecasted test year including forecasts for number of customers, energy usage, and demands. Duke's exhibits, workpapers and MSFRs are not documented, cross-referenced, or in any way linked to one another. This lack of detail has caused Technical Associates to spend over a month trying to identify, understand, follow, and then ultimately verify Duke's forecasts and adjustments.
7. During my review of Duke's case-in-chief, I developed questions regarding Duke's forecasted KWH sales. On a conference call with Duke representatives on September 30 I was directed to DEI Workpaper 6-JRB_071019 for the total forecasted residential KWH sales for 2020. The forecasted sales contained in this workpaper do not match the forecasted energy (KWH) sales volumes used in Mr. Bailey's revenue proofs ultimately found in a series of files entitled 1-5-16(a)(2) xxx.xls. In addition, Technical Associates attempted to understand Duke's forecasted revenues at present rates contained in the Company's total revenue requirement request. In reviewing Ms. Douglas' revenue requirement exhibits and after considerable searching of hundreds of undocumented files, Technical Associates found Ms. Douglas' revenue workpapers embedded in a spreadsheet that contained 51 separate tabs. However, these workpapers only contained hard-keyed total amounts such that there is no way to determine how they were developed or where they came from. Furthermore, Ms. Douglas' revenues for the Residential class do not match Mr. Bailey's revenue proof for this class. On that call, Duke committed to provide documentation showing that the revenue proof equals cost of service at current rates and that the revenue proof at current rates matches Duke witness Douglas' revenue requirement. I have not yet received the information. Therefore, I cannot verify, reconcile, or understand how Duke's revenues were derived or even if they are consistent with the forecasts.
8. I have been practicing public utility ratemaking for more than 39 years and have been involved in more than 300 rate cases. In my experience, I have not seen a rate filing that compares with the unsupported, inadequate, unorganized/undocumented nature of Duke's current filing in Indiana. These types of issues have not existed in Duke's Kentucky or North Carolina rate cases.
9. I affirm, under the penalties of perjury, that the foregoing statement are based on personal knowledge and are true and correct to the best of my knowledge, information and belief.

Glenn A. Watkins

Commonwealth of Virginia
County of Hanover

The foregoing statement was subscribed and sworn before me this this 15th day of October, 2019 by Glenn A. Watkins.

Jennifer R. Dolen, Notary Public

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2022
COMMONWEALTH OF VIRGINIA

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Glenn A. Watkins

President/Senior Economist

Technical Associates, Inc.

Consultant for the Indiana Office of Utility Consumer Counselor

Cause No. 45253

Duke Energy Indiana, LLC

October 30, 2019

Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 30th day of October to the following:

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Public's Exhibit No. 13

STATE OF INDIANA

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PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	**))))))))))))))))**	**CAUSE NO. 45253**

VERIFIED DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

OCTOBER 30, 2019

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VERIFIED DIRECT TESTIMONY OF GLENN A. WATKINS
CAUSE NO. 45253
DUKE ENERGY INDIANA, LCC

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

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 the Richmond, Virginia area. 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 39-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, Montana, Nevada, 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 Attachment GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("COMMISSION")?

A. Yes. I have provided testimony in Indiana Michigan Power's last two general rate cases (Cause Nos. 45235 and 44967), the two most recent Indianapolis Power & Light Company (Cause Nos. 44576 and 45029) and the two most recent Northern Indiana Public Service Company (Cause Nos. 44688 and 45159) rate cases.

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

A. Technical Associates has been engaged by the Office of Utility Consumer Counselor ("OUCC") to assist in its evaluation of the accuracy and reasonableness of Duke Energy Indiana's ("Duke" or "Company") forecasted energy sales and attendant revenues, retail class cost of service study, proposed distribution of revenues by class, and rate design as it relates to this rate application. The purpose of my testimony, 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 OUCC.

Q. ARE YOU SPONSORING ANY ATTACHMENTS WITH YOUR TESTIMONY?

A. Yes, I am sponsoring the filling attachments:

- Attachment GAW-1: Resume of Glenn A. Watkins;
- Attachment GAW-2: OUCC Residential KWH, Revenue and Margin Adjustment;
- Attachment GAW-3: Generation Plant Characteristics;
- Attachment GAW-4: Residential Customer Cost Analysis;
- Attachment GAW-5: Impact of OUCC KWH Adjustment to Residential Rate RS-General;
- Attachment GAW-6: Verified Statement of Jonathan Wallach
- Attachment GAW-7: Verified Statement of Glenn Watkins.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

A. While my investigation of Duke's forecasted test year (2020) level of energy sales and attendant revenues is incomplete due to a lack of data as well as inconsistencies in the Company's filing and workpapers, I have determined that Duke's forecasted Residential energy sales are significantly understated. As a result, I have adjusted Duke's forecasted amounts to reflect more a reasonable forecast for the Residential class. My adjustment affects both the Company's revenues at current rates as well as the billing determinants used for rate design purposes.

With regard to retail class cost of allocations, Duke has utilized the 4-CP method to allocate generation-related costs. While it is my opinion that the 4-CP method does not reasonably reflect cost causation, OUCC previously agreed not to oppose the 4-CP method in this case. However, the Company's class cost of service study utilizes the understated revenues for the Residential class that understates this class's rates of return at current rates.

With regard to the distribution of any overall decrease in base rate revenues authorized in this case to individual classes, I recommend that this decrease be spread across classes in inverse proportion to the Company's proposed class revenue increases. To the extent an overall increase is authorized for this case, I recommend that this increase be spread across rate schedules in proportion to the increases proposed by Duke.

With regard to Residential rate design, I recommend the Commission maintain the current level of Residential customer charges and accept Duke's structural changes to its current declining-block rate structure for Residential customers. Furthermore, I do not oppose Duke's proposed optional pilot for Residential and Small Commercial customers but recommend the Commission require Duke to collect and maintain data relating to customers' usages and billings under this experimental rate and provide periodic reports to interested parties.

Q. COULD YOU PLEASE DESCRIBE THE QUALITY OF DUKE'S COST OF SERVICE STUDY?

A. The information contained in Duke's filing was inadequate to conduct a proper investigation of its proposal, especially relating to its cost of service study. In my experience examining general rate case applications, I have always been able to review, examine and evaluate the information that the utility relied upon, as well as verify and understand how the raw data was manipulated or utilized within these studies, and able to replicate the utility's results. However, in this proceeding, Duke's cost of service study was not reasonably documented, did not provide much of the underlying information required to evaluate or fully understand its study, let alone verify the Company's results.

A description of the deficiencies in Duke's filings and the timeline on addressing these deficiencies were outlined in the Joint Motion to Amend Procedural Schedule filed by the OUCC, Citizen's Action Coalition of Indiana , and other intervenors on October 15, 2019, as well as the affidavits of Jonathan Wallach and me included with the filing, in which I stated that Duke's exhibits, workpapers and MSFRs are not documented, cross-referenced, or in any way linked to one another. Mr. Wallach's and my affidavits are included as Attachments GAW-6 and GAW-7, respectively. In the Joint Reply, filed on October 24, 2019, updated information was provided on further difficulties with Duke's filing and attempts to obtain additional information.

Q. DO YOU HAVE OTHER CONCERNS REGARDING DUKE'S PRESENTATION OF ITS COST OF SERVICE STUDY?

A. Yes. For reasons that are unclear and questions that OUCC has asked the Company but are yet unanswered, Duke has deemed every aspect of its CCOSS as confidential including the end results; i.e., rates of return by class. In my 39 years practicing public utility regulation involving hundreds of class cost of service studies, I have never seen the results of a CCOSS to be confidential. Indeed, the Company's CCOSS results are the foundation of its proposed class revenue requirements and rate design. In my opinion, the public has a right to know the basis upon which the Company has developed its proposed rates that its customers would be required to pay.

Q. HAVE YOU PARTICIPATED IN OTHER RATE CASES INVOLVING DUKE AFFILIATES?

A. Yes. I participated in a Duke Energy case in North Carolina before the North Carolina Public Utility Commission and in a 2018 case involving Duke Energy Kentucky before the Kentucky Public Service Commission. I am currently involved in a pending Duke Kentucky rate case before that Commission.

Q. HAVE YOU ENCOUNTERED THE SAME PROBLEMS IN THE OTHER DUKE PROCEEDINGS THAT YOU SEE IN THIS PROCEEDING?

A. No. The cost of service studies conducted and provided by Duke have all been fully transparent, reasonably documented, and not considered confidential. The differences between these proceedings in other States are almost night and day with regard to the quality and openness of the information provided in this case.

III. SALES AND REVENUE FORECAST

Q. DUKE IS PROPOSING TO USE A FULLY PROJECTED FUTURE TEST YEAR FOR RATEMAKING PURPOSES IN THIS CASE. HAVE YOU INVESTIGATED THE REASONABLENESS OF DUKE'S FORECASTED NUMBER OF CUSTOMERS, KWH SALES, AND RESULTING REVENUES?

A. To the best of my ability, yes. The deficiencies in the case-in-chief has made any investigation difficult. However, to the best of my ability given the limitations, I have investigated the reasonableness of the Company's forecasted Residential number of customers, KWH sales and attendant revenues. However, due to the lack of documentation, clarity, and errors provided in the Company's litany of unreferenced workpapers, and resulting time constraints, I have not been able to investigate the reasonableness of the Company's forecasted amounts for other classes; i.e., Commercial, Industrial, Other Public Authority, and Street Lighting.

Q. WHAT ARE YOUR FINDINGS REGARDING THE COMPANY'S FORECASTED NUMBER OF RESIDENTIAL CUSTOMERS, KWH SALES, AND ATTENDANT REVENUES?

A. As will be explained in detail below, the Company's forecasted KWH sales and attendant revenues for Residential customers used for ratemaking purposes (both for class cost of service purposes as well as actual rate design purposes) are significantly understated. With regard to the Company's forecasted number of Residential customers, I have found its forecast is within the range of reasonableness.

Q. HOW DID YOU DETERMINE THAT THE COMPANY'S RESIDENTIAL KWH SALES FORECAST IS SIGNIFICANTLY UNDERSTATED?

A. In order to understand my analysis, please refer to my Attachment GAW-2, page 2. The Company's KWH sales forecast is based on Duke's sales forecast prepared in the Fall of 2018 in which the Residential class MWH sales were forecasted to be 8,690,702 MWH. In this regard, and as can be seen in my Attachment GAW-2, the Company prepared an updated forecast in the Spring of 2019 (before its filing in this rate case) but elected to rely upon its prior Fall 2018 forecast for purposes of this case.

One can readily see in Attachment GAW-2 (page 2), the Company's Fall 2018 forecast is significantly lower than forecasted amounts for 2020, either in prior forecasts (Fall 2017 and 2016 forecasts), or in the more recent Spring 2019 forecast. Similarly, we can see that on a weather normalized basis, historical Residential sales during the period 2016 through 2018 have been significantly higher than the Company's forecasted Residential MWH sales used for ratemaking purposes in this case.

Q. HAVE YOU ADJUSTED THE COMPANY'S FORECASTED KWH SALES TO MORE REASONABLY REFLECT RESIDENTIAL CONSUMPTION DURING THE 2020 TEST YEAR?

A. Yes. In developing my forecasted Residential sales energy volumes (KWH), I have examined the trend in Residential weather normalized sales per customer over the most recent three-year period. As shown in the third panel of Attachment GAW-2 (page 2), we can see that the average weather normalized Residential KWH usages per customer have been 12,569 (CY 2016), 12,409 (CY 2017), and 12,513 (CY 2018). Given these reasonably consistent usages per customer over this three-year period, I have utilized an average of these amounts; i.e., 12,497 KWH per customer. I then multiplied this average per customer usage amount by the Company's Spring 2019 forecasted average number of Residential customers during 2020 of 738,993; i.e., average year 2020.

Q. WHY DID YOU RELY UPON THE COMPANY'S SPRING 2019 FORECAST FOR NUMBER OF CUSTOMERS?

A. As can be seen in the second panel of Attachment GAW-2 (page 2), as of August 2019 there were 732,118 Residential customers. I then compared the growth rate in Duke's Residential customers over the period 2016 through August 2019. As can be seen in this Attachment, Duke's Residential customers have been growing at an increasing rate over the last few years; i.e., 0.88% from 2016 to 2017, 1.44% from 2017 to 2018, and 1.62% annualized from 2018 to 2019.

Considering the actual number of Residential customers as of August 2019 was 732,118, when this amount is multiplied by the current (2019) annual growth rate of 1.62%, a Residential August 2020 customer count of 743,978 would result. Similarly, the average annual Residential customer growth rate over the 2016 through 2019 period has been 1.31%. When this annual growth rate is applied to the actual August 2019 number of customers (732,118) an August 2020 forecast of 741,733 would be obtained. In order to be conservative, I have accepted the Company's Spring 2019 forecast for the average number of customers during 2020 of 738,993.

Q. HOW DID YOU CALCULATE YOUR 2020 FORECASTED RESIDENTIAL KWH SALES?

A. As shown in the third panel of Attachment GAW-2 (page 2), I multiplied the three-year average weather normalized usage per customer of 12,497 KWH by the forecasted average year 2020 number of Residential customers of 738,993 to obtain a Residential sales forecast of 9,235,500 MWH.

Q. ARE THERE MULTIPLE SPECIFIC RATE SCHEDULES INCLUDED IN THE COMPANY'S AND YOUR FORECASTED RESIDENTIAL KWH SALES VOLUMES?

A. Yes. The Company's KWH sales forecast is made not on an individual rate schedule basis but rather on five general customer classifications that include: Residential; Commercial; Industrial; Other Public Authority; and, Street Lighting. Within what the Company defines as "Residential," there are multiple specific rate schedules. These rate schedules can be seen on page 1 of Attachment GAW-2. In order to develop revenues at current rates, Duke witness Jeffrey Bailey allocated the total "Residential" amounts to individual rate schedules as shown on page 1 of Attachment GAW-2.

I have utilized the same allocation to individual rate schedules as that used by Mr. Bailey. This enabled me to develop forecasted 2020 KWH sales by individual rate schedule.

Q. HOW DID YOU DEVELOP YOUR ADJUSTMENT TO RESIDENTIAL REVENUES AT CURRENT RATES?

A. I first calculated the weighted average base energy charges at current rates for each Residential rate schedule and multiplied these weighted average rates by my KWH sales adjustments as shown on page 1 of Attachment GAW-2. This produces a Residential base rate revenue adjustment of $31,919,717. In addition to the current base rate revenues, Duke proposes to move several riders into base rates for this case. Therefore, I calculated the current rate for those riders that are proposed to be moved into base rates of $0.045946 per

KWH.[1] This amount was then multiplied by my KWH adjustment of 544,798,635 to arrive at a tracker revenue adjustment of $25,031,335. Therefore, my total current revenue adjustment for the Residential class is $56,951,352.

Q. WITH ADDITIONAL SALES VOLUMES, WILL THE COMPANY INCUR ADDITIONAL EXPENSES?

A. Yes. By producing and selling more energy, the Company will incur additional fuel costs. As a result, I have determined that the Company's additional fuel cost will be $14,685,047 as shown on page 1 of Attachment GAW-2. This amount was developed by multiplying my sales adjustment of 544,798,635 KWH by the Company's proposed base cost of fuel of $0.026955 per KWH as set forth in the Company's Exhibit 5-F (SES).

When the additional revenues are netted against additional fuel costs, my analysis produces a before-tax margin adjustment of $42,266,005.

Q. EARLIER YOU INDICATED THAT THE COMPANY'S UNDERSTATEMENT OF RESIDENTIAL SALES AND REVENUES AFFECTS REVENUES AT CURRENT RATES AS WELL AS RESIDENTIAL RATE DESIGN. PLEASE EXPLAIN.

A. In developing specific rates by rate schedule, an individual rate is determined by dividing that rate schedule's revenue requirement by the amount of billing determinants. In the case

[1] It should be noted that during ongoing attempts to reconcile Mr. Bailey's revenue proofs by rate schedule to those contained in Company witness Douglas' revenue requirement, Mr. Bailey's tracker revenues at current rates do not match those utilized by Ms. Douglas. Finally, during a conference call on October 28, 2019, the Company informed OUCC that Mr. Bailey's revenue proof associated with tracker revenues is in error and the numbers used were based on preliminary numbers. Furthermore, the Company informed OUCC that the revenue amounts embedded in Ms. Douglas' workpapers are correct. Then, the Company informed OUCC that Ms. Douglas' total Company tracker revenues were simply allocated to individual rate classes and rate schedules. However, OUCC had spent numerous hours studying Ms. Douglas' undocumented workpapers and determined that her total tracker revenues are simply hard-keyed amounts and thus there was no way to verify or determine how the total Company tracker revenues were calculated. At the conclusion of this conference call, the Company agreed to provide such analysis to OUCC, however, at the time of writing this testimony such analysis have not been yet provided.

On a related topic, Mr. Bailey's Exhibit 8-B(JRB) shows each Residential tracker revenue at current rates. During the October 28, 2019 conference call, the Company indicated that the tracker rates shown in Mr. Bailey's Exhibit are correct and are based on forecasted 2020 amounts. However, when each Residential tracker proposed to move to base rates are added, the result is a total rate of $0.020470 per KWH. In contrast, Ms. Douglas' rider revenues that will be moving to base rates for Rate Schedules RSNO and RSN4 are $362,327,805. When this revenue amount is divided by the KWH sales utilized by both Ms. Douglas and Mr. Bailey of 7,885,943,587, the result is a tracker rate of $0.045946 per KWH. The exact same rate of $0.045946 per KWH is also obtained for Rate Schedule RSN2. Based on the Company's representation that Ms. Douglas' tracker revenues are correct (albeit unverifiable thus far), I have utilized Ms. Douglas' tracker rate for those riders moving to base rates.

of energy charges, if the revenue requirement remains constant but the amount of KWH billing determinants becomes larger, the calculated (and appropriate) energy charge rates become lower. This is most important because the ultimate outcome of this rate case is to establish fair and reasonable rates for individual rate schedules. I will further explain the rate design impact of my Residential sales adjustment later in the rate design section of my testimony.

IV. 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 tend to be allocated based on internally generated allocation factors, all allocation factors are ultimately a direct function of class contributions to: (a) demands ("kilowatt" or "KW"); (b) energy usage ("kilowatt-hour" or "KWH"); or, (c) number of customers. In this regard, energy usage and number of customers are readily known and measured from billing and financial records. However, class contributions to demands 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, such as Residential, must be estimated based on sample data since these class' meters only measure monthly energy, or 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. 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 the Federal Energy Regulatory Commission or "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.[2]

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. IS THERE A CERTAIN ASPECT OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TENDS TO BE MORE CONTROVERSIAL THAN OTHERS?

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

[2] *Colorado Interstate Gas Co. V FPC*, 324 U.S. 581, 589 (1945).

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, production facilities 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 or 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 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, or KW, and the variable cost of producing a unit of energy 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 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 investment 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") <u>Electric Utility Cost Allocation Manual</u> 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 <u>Principles of Public Utility Rates</u>.[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:

<u>Single Coincident Peak ("1-CP")</u> -- 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.

[3] <u>Principles of Public Utility Rates</u>, Second Edition, page 495, 1988.

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 had a peak load of 6,000 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 6,000 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 four highest monthly peak loads 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 is no more reasonable than the 1-CP method.

<u>12-CP</u> -- 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 or 4-CP 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.

<u>Peak and Average ("P&A")</u> -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load <u>and</u> 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.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities.

This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method, explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility's resources used to serve the varying 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.

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 units are evaluated on a case-by-case basis. This is because 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).

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. The OUCC agreed in a prior case not to oppose the use of the 4-CP for production plant in this case. Settlements involve give and take and I am not privy to why that was part of the settlement. Nonetheless, the agreement not to oppose does not change the flaws in the 4-CP methodology. Cost allocation methods that only consider peak loads (demands) such as the 1-CP and 4-CP 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 predominately comprised of nuclear and coal units installed coupled with run of the river hydro facilities that provide power throughout the year.

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 and 4-CP 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. Duke's generation portfolio is comprised of a variety of base load facilities as well as various intermediate and peaker units.

Q. CAN YOU EXPLAIN AND SHOW HOW DUKE'S PORTFOLIO OF GENERATING ASSETS ARE UTILIZED?

A. Yes. As shown in my Attachment GAW-3, the Company's base load plants produced about 95% of Duke's total owned generation energy (KWH) while its peaker plants only produced slightly more than 1% of the Company's total energy as they were only operated for a few hours of the year during peak load conditions. At the same time, when we evaluate the investments in Duke's portfolio of generation assets, we see that the vast majority (88%) of this investment is associated with base load generation that serves customers throughout the entire year. These relationships are particularly important and relevant in terms of cost causation as the Company's base load units are operated to serve load and energy requirements throughout the year while its peaker units are devoted to only serving peak load requirements.

When Duke's total generation investment costs are allocated to classes based only on a few peak hours of demand (e.g., the 4-CP method), the implicit assumption is that the Company's entire investment in generation plant is made to simply serve peak load requirements. However, as discussed above, this is clearly incorrect in that the vast majority (88%) of the Company's generation investment was made to serve customers' load and usage requirements throughout the year. Indeed, any allocation method that only considers a few hours of peak demand presents a significant bias against low load factor and weather sensitive customer classes such as the Residential class.

Q. WHAT COST ALLOCATION METHODOLOGY DOES DUKE UTILIZE TO ALLOCATE GENERATION PLANT COSTS WITHIN ITS PROPOSED CCOSS?

A. Duke witness Maria Diaz sponsors the Company's class cost of service studies. As indicated on page 6 of her revised direct testimony, Ms. Diaz conducted her studies utilizing both the 4-CP and 12-CP methods. In this regard, the 12-CP was utilized for informational purposes only in that the Company has relied upon its 4-CP study to evaluate class revenue responsibility. Furthermore, Ms. Diaz correctly notes that the OUCC agreed not to oppose the 4-CP methodology for production plant in this case based on a settlement reached in a prior proceeding (Cause No. 42873).

Q. DOES THE 4-CP METHOD REASONABLY REFLECT COST CAUSATION OF DUKE'S GENERATION PLANT AND RELATED COSTS ACROSS CLASSES?

A. No. As discussed earlier, the 4-CP only considers peak demands and does not consider the manner in which Duke's portfolio of generation assets were designed, built, or are utilized. However, in adhering to OUCC's prior commitment not to oppose the 4-CP method in this case, I have not conducted alternative CCOSS.

Q. WHAT IS THE COMPANY'S CALCULATED RESIDENTIAL ROR AT CURRENT RATES COMPARED TO THE SYSTEM AVERAGE ROR AT CURRENT RATES?

A. The Company's 4-CP CCOSS produces the following rates of return for the Residential class and the total Company.

TABLE 1
Duke 4-CP Residential and Total Retail ROR at Current Rates

Rate Schedule	Rate of Return	Relative ROR
Rate RS-General	1.85%	57%
Rate RS-High Efficiency	0.86%	26%
Total RS	1.76%	54%
Total Company Retail	3.27%	100%

Q. DOES THE COMPANY'S 4-CP CCOSS REFLECT ALL OF DUKE'S FORECASTED AND PROFORMA RATE BASE AND OPERATING INCOME AMOUNTS?

A. Yes.

Q. DO THE REVENUES IN THE COMPANY'S 4-CP CCOSS ALSO REFLECT DUKE'S FORECASTED RESIDENTIAL SALES REVENUES AT CURRENT RATES?

A. Yes.

Q. YOU HAVE DETERMINED THAT THE COMPANY'S FORECASTED REVENUES FOR THE RESIDENTIAL CLASS ARE SIGNIFICANTLY UNDERSTATED AND UNREASONABLE. HAVE YOU BEEN ABLE TO ESTIMATE THE RESIDENTIAL CLASS' RATE OF RETURN UTILIZING YOUR RECOMMENDED RESIDENTIAL REVENUES?

A. Yes. As discussed earlier, I have increased the Company's forecasted Residential revenues at current rates and variable fuel costs to arrive at a Residential before-tax margin increase of $42.266 million. While the following is not absolutely precise in that there are a few FERC accounts that are ultimately based on KWH volumes, the majority of costs allocated on a KWH basis relate to fuel costs. As such, the analysis that follows provides a reasonable estimate of the Residential class rate of return at current rates under the 4-CP method and incorporating my Residential revenue and fuel cost adjustment:

(1) Duke Residential NOI at Current Rates:	$84,780,388
(2) OUCC Before-Tax Margin Adjustment:	$42,266,005
(3) Revenue Conversion Factor:	1.34318
(4) OUCC NOI Adjustment (2) ÷ (3):	$31,467,119
(5) OUCC Revised Residential NOI (1) + (4):	$116,247,507
(6) Residential Rate Base:	$4,813,276,741
(7) OUCC Revised Residential ROR:	2.42%
(8) OUCC Revised Residential Relative ROR:	74%

V. CLASS REVENUE ALLOCATION

Q. WHAT METHOD DID THE COMPANY USE TO ALLOCATE ITS PROPOSED OVERALL $394.6 MILLION INCREASE TO INDIVIDUAL CLASSES?

A. Based on my examination of the Company's filing exhibits and workpapers, Duke's class revenue allocation method is based upon its 4-CP CCOSS results wherein each class's so-called "subsidy" or excess is calculated; i.e., the difference between calculated cost of service revenues and current revenues. Then, the Company proposes to reduce these so-called subsidies or excess by 5.1% for each class.

Q. WHAT ARE THE COMPANY'S PROPOSED REVENUE INCREASES FOR THE RESIDENTIAL CLASS?

A. The following table provides the Company's proposed Residential rate increases compared to the total Company proposed revenue increase:

TABLE 2
Duke Proposed Residential Revenue Increase

	Current Rates						
Rate	Base Rate Revenue a/	Trackers Moving To Base Rates b/	Total Current Revenue	Duke Proposed Revenue a/	Increase	% Increase	% of Average
RS - General	$544,189,847	$362,327,805	$906,517,652	$1,081,072,007	$174,554,355	19.26%	123%
RSN2 - HE	$45,195,160	$35,882,132	$81,077,292	$98,251,276	$17,173,984	21.18%	135%
Total Rate RS	$589,385,007	$398,209,937	$987,594,944	$1,179,323,283	$191,728,339	19.41%	124%
TOTAL DUKE RETAIL c/	Unknown	Unknown	$2,517,951,958	$2,912,522,000	$394,570,042	15.67%	100%

a/ Per Bailey Workpaper 1-5-16(a)(2) Workpaper 2_RS Rate Design Summary. Note: Excludes non-rate revenue for RS.
b/ Per Revised MSFR Workpaper REV2-DLD and response to Informal COSS Data Request 1.6-C.
c/ Per Petitioner's Exhibit 4-E (DLD). Note: Includes non-rate revenue.

Q. IS THE SO-CALLED RESIDENTIAL "SUBSIDY" SMALLER WITH THE INCORPORATION OF YOUR RESIDENTIAL REVENUE ADJUSTMENT?

A. Yes. Duke calculates the Residential so-called subsidy to be $72.470 million. However, as discussed earlier, my Residential revenue adjustment increases the Residential net operating income under the 4-CP method by $31.467 million thereby reducing this so-called subsidy by this same amount such that the adjusted Residential "subsidy" becomes $41.003 million.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSED INCREASE TO THE RESIDENTIAL CLASS?

A. Although no class cost of service study is surgically precise and therefore should only be used as one of the many tools in establishing class revenue responsibility, OUCC has agreed not to oppose the 4-CP method for purposes of this case. Furthermore, my revenue adjustment indicates that the so-called Residential revenue "subsidy" is significantly less than that portrayed by Duke. When all factors are considered, it is my opinion that the Company's proposed increase to the Residential class is reasonable under the Company's proposed overall revenue increase.

Q. OUCC WITNESS KOLLEN IS RECOMMENDING AN OVERALL REVENUE REDUCTION FOR THIS CASE. HOW SHOULD THIS REDUCTION TO CURRENT REVENUES BE ALLOCATED ACROSS CLASSES?

A. I recommend that any overall reduction to the Company's overall revenue requirement be allocated to classes in inverse proportion to the Company's proposed increases. In other words, those classes that receive smaller increases would receive larger decreases while those classes that receive larger increases would receive smaller decreases. These decreases would be in inverse proportion by class.

Q. TO THE EXTENT THE COMMISSION AUTHORIZES AN OVERALL INCREASE LESS THAN THAT REQUESTED BY DUKE, HOW SHOULD THE OVERALL INCREASE BY ALLOCATED ACROSS CLASSES?

A. I recommend that any reduction in the authorized overall increase be scaled-back proportionately based on the Company's proposed class revenue allocation.

VI. <u>RESIDENTIAL RATE DESIGN</u>

Q. PLEASE EXPLAIN THE COMPANY'S CURRENT RESIDENTIAL RATE STRUCTURES.

A. Duke offers two separate rate schedules for traditional Residential customers: Rate RS-General and Rate RS-High Efficiency. With regard to Rate RS-General (the rate under which the vast majority of Residential customers take service), the fixed monthly customer charge is currently $9.01. With respect to existing energy charges, there is a three-tiered severely declining-block rate structure wherein the first usage block is priced at $0.089116, the second usage block ($0.051948) is priced 41.7% lower than the first usage block, and the third usage block ($0.042634) is priced 52.2% lower than the first usage block. In addition, Residential customers are subject to 12 separate riders.

With regard to Rate RS-High Efficiency, this rate schedule is closed to new customers as well as closed to existing Rate RS-General customers that would otherwise desire this rate schedule. The fixed monthly charge is also $9.01 per month. This rate schedule also utilizes a three-tiered severely declining-block rate structure with the same energy rates as Rate RS-General for the Summer months (July through October) but provides for an even larger discount in the third usage block during the non-Summer months (November through June). For Rate RS-High Efficiency, the non-Summer third block of $0.036235 is priced 59.3% lower than the first usage block.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RATE RS-GENERAL RATES AND RATE STRUCTURE.

A. As set forth in the revised direct testimony of Company witness Bailey, Duke proposes two rate design options relating to Rate RS-General. The Company's first, and preferred option, is if Duke is allowed to implement decoupling in this case; its second option is without decoupling. The following tables presents Duke's proposed Rate RS-General under both options:

TABLE 3
Rate RS-General
Duke Proposed Rate Design w/ Decoupling

Description	Rate	Percent Reduction To 1st Usage Block
Customer Charge	$9.80	
Energy Charges:		
1st Block (0-300)	$0.150893	--
2nd Block (301-1,000)	$0.122344	18.9%
3rd Block (>1,000)	$0.110347	26.9%

TABLE 4
Rate RS-General
Duke Proposed Rate Design w/o Decoupling

Description	Rate	Percent Reduction To 1st Usage Block
Customer Charge	$10.54	
Energy Charges:		
1st Block (0-300)	$0.160859	--
2nd Block (301-1,000)	$0.117074	27.2%
3rd Block (>1,000)	$0.106102	34.0%

Q. WHAT RATIONALE DOES THE COMPANY PROVIDE FOR ITS PROPOSED FIXED MONTHLY CUSTOMER CHARGES OF $9.80 WITH DECOUPLING OR $10.54 WITHOUT DECOUPLING?

A. In his Exhibit 8-D (JRB), Mr. Bailey indicates that his calculated Residential customer cost is $9.80 per month. Although the Company has not provided any information as to exactly which FERC accounts are included in this calculation (or how this amount was calculated), Mr. Bailey states on page 6 of his revised direct testimony that this amount includes customer accounts, customer service and information, allocated general and intangible rate base and "certain expenses including billing, bad debts, and customer service."

With regard to the Company's proposed $10.54 per month Residential customer charge if decoupling is not approved, I have no idea how Mr. Bailey developed this amount. Mr. Bailey provides no calculation or explanation as to the elements of the customer charge or how the increase was determined. However, Mr. Bailey does state in his revised direct testimony that his rate design without decoupling presents "a modest reduction in risk to the Company." With this statement, I interpret Mr. Bailey's intention under the rate design option without decoupling to simply reduce risk to the Company because fixed customer charges represent guaranteed revenue recovery and that a more severe declining-block rate also reduces primarily weather-related risk to the Company.[4]

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 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 an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

[4] The majority of Residential usage in the third rate block occurs during the Winter and Summer months wherein weather in a given month is the primary determinant of usage in the third block.

Under this direct customer cost approach, there is no provision to include corporate overhead expenses or any other indirect costs in the customer charge. As explained below, these costs are more appropriately recovered through energy (KWH) charges.

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

A. Yes. I conducted a direct customer cost analysis of Duke's Residential class. The details of this analysis are provided in my Attachment GAW-4. As indicated in this Attachment, the Residential direct customer cost is calculated to be between $8.59 and $8.87 per month. The lower cost of $8.59 is based on a 9.0% return on equity as recommended by OUCC witness David Garrett, while the higher cost of $8.87 is based on the Company's requested return on equity of 10.40%. In this regard, a cost of equity of even 9.0% overstates the risks associated with fixed monthly customer charges. This is because customer charges are "fixed" charges such that Residential customers must pay this charge every month, even with no energy usage, and there is virtually no risk associated with this charge.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS SUCH AS GENERAL AND INTANGIBLE RATE BASE AS WELL AS ALL BAD DEBT EXPENSES IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all electric utilities, Duke is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to Duke's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT ARE YOUR RECOMMENDATIONS REGARDING RESIDENTIAL RATE DESIGN FOR THIS CASE?

A. Although my customer cost analysis indicates that a customer charge of no more than $8.59 is warranted, I recommend that the current Residential monthly customer charges of $9.01 for both Rate RS-General and Rate RS-High Efficiency be maintained at their current levels. Maintaining the current Residential customer charges will promote rate continuity as well as encouraging conservation as any increase authorized in this case will be collected from the Residential energy charges, thereby sending a more appropriate price signal for customers to conserve and use energy more efficiently. As a very slight adjustment, a customer charge of $9.00 plus $0.01 makes little sense and I suggest that an even $9.00 per month Residential customer charge is more appropriate.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO MAINTAIN ITS DECLINING-BLOCK ENERGY CHARGES FOR THE RESIDENTIAL CLASS.

A. As discussed earlier, Duke's current Residential energy charges consist of a three-tiered severely declining-block rate structure. In this regard, Mr. Bailey acknowledges on pages 4 and 5 of his revised direct testimony that the magnitude of the declining-block rates "would be difficult to justify today." As a result, Mr. Bailey does recommend reducing the discount in the second and third usage blocks under both of his rate design options (with and without decoupling). In my opinion, this is a step in the right direction in that declining-block rate structures were originally developed as a promotional tool to encourage additional electricity consumption. However, in this day of conservation consciousness, such promotional rate designs have been discouraged and found to be contrary to public policy conservation efforts.

Q. WHAT IS YOUR OPINION REGARDING MR. BAILEY'S TWO SEPARATE RESIDENTIAL RATE DESIGN OPTIONS WITH AND WITHOUT REVENUE DECOUPLING?

A. As stated earlier, Mr. Bailey's proposed rate design without decoupling was developed simply to reduce the Company's risk. While I agree that higher customer charges coupled with more precipitous declining-block energy rates does indeed reduce the Company's risk, this should not be a driving factor for reasonable rate design.

Q. EARLIER YOU INDICATED THAT THE COMPANY'S UNDERSTATEMENT OF FORECASTED RESIDENTIAL KWH ENERGY SALES AFFECTS THE RATE DESIGN FOR THE RESIDENTIAL CLASS. HAVE YOU PREPARED AN ATTACHMENT TO SHOW THE RATE DESIGN IMPACT OF YOUR KWH SALES ADJUSTMENT.

A. Yes. My Attachment GAW-5, which consists of two pages, shows the rate design impact on the Residential Rate RS-General schedule. Page 1 of this Attachment shows the impact on energy charge rates utilizing the Company's proposed customer charge of $9.80 per month and using the Company's Residential revenue requirement. Page 2 of this Attachment shows the impact on energy charge rates utilizing my recommended customer charge of $9.01 per month and using the Company's Residential revenue requirement.

As shown on both pages 1 and 2 of Attachment GAW-5, the energy rates are lower with the incorporation of my KWH sales adjustment simply due to the fact that there are more KWH billing determinants to collect this rate schedule's revenue requirement.

Q. HAVE YOU CALCULATED THE BILL IMPACT OF YOUR SALES ADJUSTMENT FOR A TYPICAL RESIDENTIAL CUSTOMER?

A. Yes. For a typical Rate RS-General customer using 1,000 KWH per month, the bill impact utilizing the Company's proposed $9.80 monthly customer charge is $7.72 per month while the bill impact utilizing my recommended $9.01 monthly customer charge is $7.68 per month. That is, by reflecting a more appropriate level of forecasted KWH sales, this typical customer's bill would be about $7.70 lower per month.

Q. DO YOU HAVE ANY COMMENTS OR RECOMMENDATIONS RELATING TO THE COMPANY'S PROPOSED OPTIONAL RESIDENTIAL AND SMALL COMMERCIAL PILOT RATES?

A. Yes. Duke is proposing a pilot program to utilize dynamic pricing that will be available to those customers with Smart Meters. Mr. Bailey discusses these optional pilot rates on pages 15 through 21 of his revised direct testimony. Because these proposed rate schedules are optional in that they will provide customers with another service alternative, I do not object to this proposed pilot rate. However, the purpose of every pilot, or experimental, program is to gather and obtain information. As such, if the pilot is approved, I recommend the Commission direct Duke to keep and maintain specific records on a customer by customer basis that compares each customer's actual bills (and billing determinants) to those that would have resulted under Rate RS. Furthermore, the Company should be required to submit detailed reports, data, and workpapers to the Commission, OUCC, and other interested parties on at least an annual basis concerning customer impacts and changes and in energy usage and peak load as a result of the critical peak pricing structure.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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. Public Utility Regulation

A. Costing Studies -- 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. Rate Design Studies -- 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

DUKE ENERGY INDIANA
OUCC Residential KWH, Revenue and Margin Adjustment

3-Year Average Weather Normalized Residential Usage Per Customer (KWH) 1/	**12,497**
Duke Forecasted 2020 Average Year No. of Residential Customers (Spring '19 Forecast) 1/	**738,993**
OUCC Forecasted 2020 Residential KWH Sales 1/	**9,235,500,317**

Allocate to Rate Codes:

Residential Code	Residential Name	Duke KWH Forecast Allocated Amount 2/	Duke KWH Forecast Allocation Percent	OUCC KWH Forecast Allocated Amount 3/	OUCC KWH Forecast Sales Adjustment	Weighted Average Base Energy Charge 4/	OUCC Base Revenue Adjustment
LSNO	GS - LLF No Meter Adj.	4,656,817	0.0536%	4,948,741	291,924	$0.056486	$16,490
LSN4	Farm - LLF	3,164,305	0.0364%	3,362,667	198,362	$0.056486	$11,205
RSNO	RS - General	7,848,601,252	90.3103%	8,340,610,690	492,009,438	$0.059290	$29,171,396
RSN2	RS - High Efficiency	780,912,177	8.9856%	829,865,634	48,953,457	$0.051916	$2,541,486
RSN4	RS - Farm Service	33,630,605	0.3870%	35,738,825	2,108,220	$0.059290	$124,997
SMLC	Metered OL - Company Owned	1,629	0.0000%	1,731	102	$0.031568	$0
SMLP	Metered OL - Customer Owned	6,652	0.0001%	7,069	417	$0.031568	$13
UOLS	Unmetered OL	19,728,245	0.2270%	20,964,960	1,236,715	$0.043770	$54,131
Total Residential		8,690,701,682	100.0000%	9,235,500,317	544,798,635	--	$31,919,717

OUCC Base Rate Revenue Adjustment	$31,919,717
Residential Riders Moving to Base Rates	$0.045946 5/
OUCC Tracker Revenue Adjustment	$25,031,335
OUCC Total Revenue Adjustment	**$56,951,052**
Fuel Cost per KWH	$0.026955 6/
OUCC Fuel Cost Adjustment	$14,685,047
OUCC Margin Adjustment	**$42,266,005**

1/ Per Page 2.
2/ Per 45253 DEI Workpaper 6-JRB 071019.xls, Tab: Rate Calc Sheet and 10/21/19 Affidavit of Jeffrey Bailey.
3/ Total Residential per Page 2 and allocated to rate schedules per Duke allocation percentages.
4/ Calculated per Bailey Workpapers [1-5-16(a)(2)].
5/ Calculated per Douglas Revised MSFR Workpaper REV2-DLD [1-5-8(a)(2)], Column F (Tracker Revenue Moving to Base Rates) divided by forecasted KWH per Bailey Rate Design [1-5-16(a)(2)] (Workpaper 2_RS Rate Design Summary.xlsm) and also Duke response to CAC 12.7-C.
6/ Per Petitioner's Exhibit 5-F(SES) and response to Informal COSS Data Request 1.6-D.

DUKE ENERGY INDIANA
OUCC Residential 2020 MWH Forecast

I. Residential MWH Sales

Forecast	2016	2017	2018	2019	2020		2021	YTD Aug. 2019	
Spring- 19 1/				9,040,555	9,051,878		9,069,214	6,269,458	
Fall - 18 1/				8,767,201	$\boxed{8,690,702}$		8,684,328	6,079,090	
Fall - 17 1/			8,912,069	8,945,246	8,999,658		9,027,839	6,268,904	
Fall - 16 1/		8,842,896	8,956,582	8,986,150	9,049,001		9,059,245	6,318,274	
Actual 2/	8,917,714	8,574,832	9,648,621					6,347,489	
Weather Normalized 2/	8,896,439	8,860,619	9,063,096					6,247,745	
Claimed Rate Case MWH					**8,690,702**	3/		6,014,621	4/

II. Number of Residential Customers EOY

Forecast	2016	2017	2018	2019	2020	2021	YTD Aug. 2019
Spring- 19 1/				735,765	742,220	748,109	726,442
Fall - 18 1/				733,045	737,796	743,877	722,249
Fall - 17 1/			727,573	733,324	738,829	743,988	720,557
Fall - 16 1/		716,830	720,212	724,158	728,018	731,468	710,702
Actual 2/	707,782	714,024	724,272				732,118
Annual Growth Rate		0.88%	1.44%	1.62%			
				Actual YTD Annualized to Year End			
Annualized Amount				736,041			

III. OUCC Forecasted 2020 Residential KWH Sales

	2016	2017	2018	2019	2020	2021	YTD Aug. 2019
Avg KWH Use/Cust Weather Normalized	12,569	12,409	12,513				
3-Year Average Weather Normalized Use Per Customer					12,497		
2020 Avg. Yr. No. of Cust. Based on Spring '19 Forecast					738,993		
OUCC KWH Forecast							**9,235,500,317**

1/ Per response to OUCC 4.1 attach A
2/ Per response to OUCC 4.1 attach C
3/ Per 45253 DEI Workpaper 6-JRB 071019.xls, Tab: Rate Calc Sheet and 10/21/19 Affidavit of Jeffrey Bailey.
4/ Per 45253 DEI Workpaper 6-JRB 071019.xls, Tab: Rate Calc Sheet.

DUKE ENERGY INDIANA
Generation Plant Characteristics

	Plant	Nameplate Capacity (MW)	Net Generation KWH	Net Generation % of Total	Total Cost $	Total Cost % of Total	Fuel Cost	Capacity Factor	Installed Cost Per KW	Fuel Cost Per KWH
Base Load	Cayuga	1,062	5,922,853,336	20.58%	1,577,717,537	16.89%	$ 145,590,321	63.7%	$ 1,486	$ 0.0246
	Noblesville	283	1,506,408,000	5.23%	263,657,519	2.82%	$ 39,135,299	60.8%	$ 932	$ 0.0260
	Gibson	3,006	15,937,485,000	55.37%	3,654,126,563	39.13%	$ 341,883,869	60.5%	$ 1,216	$ 0.0215
	Edwardsport IGCC	805	3,962,017,000	13.76%	2,711,641,162	29.04%	$ 108,040,770	56.2%	$ 3,371	$ 0.0273
	Total Base Load	**5,156**	**27,328,763,336**	94.95%	**8,207,142,781**	87.88%	**634,650,259**	**60.5%**	**$ 1,592**	**$ 0.0232**
Intermediate	Cadiz (Henry County)	182	283,650,000	0.99%	88,428,408	0.95%	$ 10,017,234	17.8%	$ 487	$ 0.0353
	Gallagher	300	285,152,000	0.99%	441,219,186	4.72%	$ 12,710,573	10.9%	$ 1,471	$ 0.0446
	Madison	692	541,948,000	1.88%	334,051,154	3.58%	$ 27,456,755	8.9%	$ 483	$ 0.0507
	Total Intermediate	**1,174**	**1,110,750,000**	3.86%	**863,698,748**	9.25%	**50,184,562**	**10.8%**	**$ 736**	**$ 0.0452**
Peaking	Wheatland	500	191,791,000	0.67%	109,801,445	1.18%	$ 9,598,467	4.4%	$ 219	$ 0.0500
	Vermillion	433	151,998,000	0.53%	155,348,430	1.66%	$ 7,507,671	4.0%	$ 359	$ 0.0494
	Cayuga Peaking	10	290,000	0.00%	2,792,527	0.03%	$ 49,493	0.3%	$ 269	$ 0.1707
	Total Peaking	**943**	**344,079,000**	1.20%	**267,942,402**	2.87%	**17,155,631**	**4.2%**	**$ 284**	**$ 0.0499**
Total		**7,272**	**28,783,592,336**	100.00%	**9,338,783,931**	100.00%	**701,990,452**			
Other	Wabash River	473	-		-		$ -	0.0%	$ -	$ -
	Miami Wabash	87	(33,000)		-		$ -	0.0%	$ -	$ -
	Connersville	84	(108,000)		-		$ -	0.0%	$ -	$ -
	Cayuga CT	113	(157,000)		53,107,158		$ 29,842	0.0%	$ 472	$ -
	Total Other	**756**								

Source: FERC Form 1, 2018.

DUKE ENERGY INDIANA
Residential Customer Cost Analysis

		Duke Proposed ROE		OUCC Proposed ROE	
		RSNO	**RSN2**	**RSNO**	**RSN2**
Gross Plant					
369	Services	$257,019,641	$15,733,814	$257,019,641	$15,733,814
370	Meters	$87,179,406	$5,336,809	$87,179,406	$5,336,809
	Total Gross Plant	$344,199,047	$21,070,623	$344,199,047	$21,070,623
Depreciation Reserve					
	Services	-$154,459,231	-$9,455,437	-$154,459,231	-$9,455,437
	Meters	-$18,288,689	-$1,119,568	-$18,288,689	-$1,119,568
	Total Depreciation Reserve	-$172,747,920	-$10,575,005	-$172,747,920	-$10,575,005
Total Net Plant		$171,451,127	$10,495,618	$171,451,127	$10,495,618
Operation & Maintenance Expenses					
586	Dist Oper - Meter	$3,878,096	$237,403	$3,878,096	$237,403
587	Customer Installations	$21,469,342	$1,314,276	$21,469,342	$1,314,276
902	Meter Reading	-$46,921	-$2,872	-$46,921	-$2,872
903	Customer Records	$19,749,615	$1,209,000	$19,749,615	$1,209,000
	Total O & M Expenses	$45,050,132	$2,757,807	$45,050,132	$2,757,807
Depreciation Expense					
	Services	$4,675,264	$286,203	$4,675,264	$286,203
	Meters	$5,730,706	$350,813	$5,730,706	$350,813
	Total Depreciation Expense	$10,405,970	$637,016	$10,405,970	$637,016
Revenue Requirement					
	Interest	$3,926,231	$240,350	$3,994,811	$244,548
	Equity return	$9,457,518	$578,955	$7,715,301	$472,303
	State Income Taxes	$537,217	$32,886	$438,254	$26,828
	Federal Income Tax	$2,371,219	$145,157	$1,934,405	$118,417
	Revenue For Return	$16,292,186	$997,349	$14,082,770	$862,096
	O & M Expenses	$45,050,132	$2,757,807	$45,050,132	$2,757,807
	Depreciation Expense	$10,405,970	$637,016	$10,405,970	$637,016
	Subtotal Customer Revenue Requirement	$71,748,288	$4,392,172	$69,538,872	$4,256,919
	Total Revenue Requirement	$71,748,288	$4,392,172	$69,538,872	$4,256,919
	Number of Bills	8,126,256	497,460	8,126,256	497,460
	Monthly Cost Before Bad Debts & Utility Receipts Tax	$8.83	$8.83	$8.56	$8.56
	Bad Debts + Public Utility Fee	0.4087%	0.4087%	0.4087%	0.4087%
	TOTAL MONTHLY CUSTOMER COST	**$8.87**	**$8.87**	**$8.59**	**$8.59**

DUKE ENERGY INDIANA
Impact of OUCC KWH Adjustment to Residential Rate RS-General 1/
Based on Duke Proposed Customer Charge

			Duke Forecasted Sales			OUCC Forecasted Sales		
Description			Customer Bills and KWH	2020 Pro Forma Rate	Annualized Revenue at Pro Forma 2020 Rates	Customer Bills and KWH	2020 Pro Forma Rate	Annualized Revenue at Pro Forma 2020 Rates
Customer Bills			8,510,599	$ 9.80	$ 83,402,737	8,510,599	$ 9.80	$ 83,402,737
Energy	Begin	End						
1st Block	0	300	2,152,932,276	$ 0.150893	$ 324,861,714	2,287,830,763	$ 0.141996	$ 324,861,714
2nd Block	301	1000	3,358,190,351	$ 0.122344	$ 410,854,848	3,568,607,929	$ 0.115130	$ 410,854,848
3rd Block	1001	1000	-	$ 0.110347	$ -	-		$ -
4th Block	1001	1000	-	$ 0.110347	$ -	-		$ -
End Block	1001	and Over	2,374,820,960	$ 0.110347	$ 262,053,531	2,523,622,553	$ 0.103840	$ 262,053,531
Total Energy			7,885,943,587		$ 997,770,093	8,380,061,245		997,770,093
Calculated Revenue					$ 1,081,172,830			1,081,172,830
Correction Factor					0.999906747			0.999906747
Total Proforma Revenue before Other Adjustments					$ 1,081,072,007			$ 1,081,072,007

1/ Includes Rate codes RSNO and RSN4.

DUKE ENERGY INDIANA
Impact of OUCC KWH Adjustment to Residential Rate RS-General 1/
Based on Maintaining the Current Customer Charge

Description			Duke Forecasted Sales: Customer Bills and KWH		2020 Pro Forma Rate		Annualized Revenue at Pro Forma 2020 Rates	OUCC Forecasted Sales: Customer Bills and KWH	2020 Pro Forma Rate		Annualized Revenue at Pro Forma 2020 Rates
Customer Bills			8,510,599	$	9.80	$	83,402,737	8,510,599	$ 9.01	$	76,680,497
Energy	Begin	End									
1st Block	0	300	2,152,932,276	$	0.150893	$	324,861,714	2,287,830,763	$ 0.142952	$	327,050,393
2nd Block	301	1000	3,358,190,351	$	0.122344	$	410,854,848	3,568,607,929	$ 0.115906	$	413,622,886
3rd Block	1001	1000	-	$	0.110347	$	-	-		$	-
4th Block	1001	1000	-	$	0.110347	$	-	-		$	-
End Block	1001	and Over	2,374,820,960	$	0.110347	$	262,053,531	2,523,622,553	$ 0.104540	$	263,819,055
Total Energy			7,885,943,587			$	997,770,093	8,380,061,245			1,004,492,333
Calculated Revenue						$	1,081,172,830				1,081,172,830
Correction Factor							0.999906747				0.999906747
Total Proforma Revenue before Other Adjustments						$	1,081,072,007			$	1,081,072,007

1/ Includes Rate codes RSNO and RSN4.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED STATEMENT OF JONATHAN WALLACH

1. My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

2. I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

3. Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

4. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility Regulatory Commission ("the Commission") in Cause Nos. 44967, 45029, 45159, and 45235.

5. I have testified in more than 30 general rate cases across the nation, including in Duke Energy's most recent general rate cases in North and South Carolina.

6. I have reviewed Duke Energy Indiana's ("Duke" or the "Company") pre-filed testimony in Cause No. 45253 and have reviewed the primary results of Citizens Action Coalition's ("CAC") discovery on the Company in Cause No. 45253 to date. I have participated in several phone calls with the Company throughout September and October, attempting to find critical information for my case-in-chief filing that has been extremely burdensome and time-consuming for my team at Resource Insight and me to find ourselves.

7. During my review of Duke's case-in-chief testimony, workpapers, MSFRs, and exhibits in late-August of 2019, I discovered that the presented Cost of Service Study ("COSS") workpaper did not actually functionalize, classify, and allocate test-year costs. In other words, Confidential Workpaper 2-MTD, sheet RC ALOCC, does not have any formulas or other critical pieces of information, just 69,000+ rows of output data from the Company's proprietary COSS software model pasted in. I notified CAC's counsel so she could request Duke to provide a copy of the COSS that would allow me to review the necessary information to perform my analysis for my case-in-chief submission.

8. On September 19, 2019, I attended a call with various Duke representatives and other consumer parties interested in the COSS to discuss how parties were having difficulty finding critical information that should be located in the MSFRs, workpapers, and exhibits and how best to rectify the situation. Duke provided a preview of their proprietary model via Skype and received multiple questions from expert witnesses as it became clear that this presentation did not show how this new model performed the functionalization, classification, and allocation of costs as a traditional spreadsheet-based COSS model would. It also became clear that Duke had not provided a clear statement or chain of evidence in terms of which information was being fed into the model or calculated within the model and provided as an output somewhere in the Company's MSFRs or workpapers. Experts asked several questions with regard to how this new model actually worked and where experts could figure out whether critical information was fed into, represented in, and/or coming out of the model. Experts also asked several questions with regard to where they could find certain information and supporting information that had been difficult to locate on their own. For example, experts asked questions and voiced concerns about how the load data is fed into or calculated in the model, how external allocators were developed, and where to find the loss factors. I found it concerning that the Duke representatives themselves were struggling with where to find certain information. They also admitted that certain information, like detailed O&M expenses by FERC account, were rolled up into summarized information as an output from Duke's proprietary COSS software model and had not been provided at the detailed level in their case-in-chief submission. They further confirmed our concerns that their chain of evidence was broken between various spreadsheets at issue in this case, meaning that with the information provided, when Duke reaches a result in one spreadsheet, it merely copies those numbers and pastes them into the next spreadsheet, not linking the spreadsheets in any way or even leaving a citation trail so that parties could reasonably find where the next logical chain of evidence would be. In my experience, Commissions have required and utilities have presented information with a clear and transparent chain of information with spreadsheets linked between each other.

On the call, Duke agreed to put forth some spreadsheets with formulae intact for experts and counsel to review and discuss with Duke the following week.

9. On September 23, 2019, Duke provided an Excel-based replica of the COSS software model via email broken into two separate Excel workbooks (Class and Functional Allocation workbooks).

10. On September 25, 2019, I participated in another phone/Skype call with Duke and various other consumer representatives interested in the COSS issues. On this call, certain parties pointed out several deficiencies in these two Excel workbooks, and Duke agreed to attempt to correct those and supplement it with a new version of the Excel based replica of the COSS model. One major deficiency CAC asked Duke to address was the fact that the allocation factors had been copied as values from various undocumented MSFRs and workpapers, making it impossible for the parties to follow the chain of evidence regarding the derivation of those allocation factors. Duke later provided a key attempting to address this deficiency, which has been helpful, but has not come close to addressing the problem. Another concern voiced on this call was whether Duke would agree to make specifically requested changes to the COSS model for parties for purposes of their analysis—a standard discovery function in my experience and an elevated concern here considering Duke's reliance on a new model. Duke also admitted on this call that they had created an earlier version of this Excel-based replica of the COSS model to verify the proprietary model results, yet they just made it available to parties on September 23, 2019.

11. On September 30, 2019, Duke provided parties with a second version of the Excel-based replica of the COSS model via email. In this new version, Duke combined the Class and Functional Allocation files into one file, simplified the mapping from the Function Allocation sheets to the COSS, added an Adjustment column to the Function Allocation sheets, grouped the Input sheets into one section, added Net Operating Income and Rate Increase workpapers COSS16-26, added an "Impact of Changes" sheet to compare the results from any changes made in this file to amounts filed in the rate case, and added a second level reference to the allocation factor input sheets.

12. Throughout the week of September 30, 2019, I worked to gather a more comprehensive list of deficiencies and outstanding issues to again bring to Duke along with a proposal for a request for extension to the current procedural schedule. It is my understanding that Duke rejected our request to refile the MSFRs, workpapers, and exhibits so as to improve the documentation, cross-referencing, and linkage between these spreadsheets, which has and will continue to significantly impair my ability to complete my analysis at all, but especially for an October 30, 2019 due date. It is also my understanding that Duke rejected our request for a three-week extension, despite our stated concern that we spent over a month working to try and figure out the COSS issue.

13. In my experience, I have never seen a rate filing that compares to this in terms of the unsupported, inadequate, unorganized, and undocumented presentation of evidence. I can attest to the fact that these issues did not exist in the most recent Duke Energy Carolinas rate case, Docket No. 2018-319-E before the South Carolina Public Utilities Commission.

14. I affirm, under the penalties of perjury, that the foregoing statements are based on personal knowledge and are true and correct to the best of my knowledge, information and belief.

Further I say not.

Jonathan F. Wallach
October 11, 2019

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED STATEMENT OF GLENN WATKINS

1. My name is Glenn A. Watkins. I am President and Senior Economist with Technical Associates, Inc., 6377 Mattawan Trail, Mechanicsville, Virginia 23116.
2. I have worked as a consultant to the utility industry since 1980. During my career 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.
3. I have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I have provided expert testimony before State and Federal courts as well as before State legislatures.
4. I have testified in numerous general rate cases across the country including Duke Energy's most recent general rate case in Kentucky (2018), a Duke Energy rate case in North Carolina (2009) and am currently engaged in the pending Duke Energy of Kentucky general rate case.
5. I have reviewed Duke Energy Indiana's ("Duke") pre-filed testimony in Cause No. 45253 and have issued and reviewed pertinent discovery responses to date. I have participated in several phone calls with Duke throughout September and October, attempting to ascertain critical information for my review and preparation of my direct testimony. Throughout this case, it has been extremely burdensome and time-consuming for me and my team at Technical Associates to locate critical information.

6. Duke's rate filing reflects a forecasted test year including forecasts for number of customers, energy usage, and demands. Duke's exhibits, workpapers and MSFRs are not documented, cross-referenced, or in any way linked to one another. This lack of detail has caused Technical Associates to spend over a month trying to identify, understand, follow, and then ultimately verify Duke's forecasts and adjustments.
7. During my review of Duke's case-in-chief, I developed questions regarding Duke's forecasted KWH sales. On a conference call with Duke representatives on September 30 I was directed to DEI Workpaper 6-JRB_071019 for the total forecasted residential KWH sales for 2020. The forecasted sales contained in this workpaper do not match the forecasted energy (KWH) sales volumes used in Mr. Bailey's revenue proofs ultimately found in a series of files entitled 1-5-16(a)(2) xxx.xls. In addition, Technical Associates attempted to understand Duke's forecasted revenues at present rates contained in the Company's total revenue requirement request. In reviewing Ms. Douglas' revenue requirement exhibits and after considerable searching of hundreds of undocumented files, Technical Associates found Ms. Douglas' revenue workpapers embedded in a spreadsheet that contained 51 separate tabs. However, these workpapers only contained hard-keyed total amounts such that there is no way to determine how they were developed or where they came from. Furthermore, Ms. Douglas' revenues for the Residential class do not match Mr. Bailey's revenue proof for this class. On that call, Duke committed to provide documentation showing that the revenue proof equals cost of service at current rates and that the revenue proof at current rates matches Duke witness Douglas' revenue requirement. I have not yet received the information. Therefore, I cannot verify, reconcile, or understand how Duke's revenues were derived or even if they are consistent with the forecasts.
8. I have been practicing public utility ratemaking for more than 39 years and have been involved in more than 300 rate cases. In my experience, I have not seen a rate filing that compares with the unsupported, inadequate, unorganized/undocumented nature of Duke's current filing in Indiana. These types of issues have not existed in Duke's Kentucky or North Carolina rate cases.
9. I affirm, under the penalties of perjury, that the foregoing statement are based on personal knowledge and are true and correct to the best of my knowledge, information and belief.

Glenn A. Watkins

Commonwealth of Virginia
County of Hanover

The foregoing statement was subscribed and sworn before me this this 15th day of October, 2019 by Glenn A. Watkins.

Jennifer R. Dolen, Notary Public

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2022
COMMONWEALTH OF VIRGINIA

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Glenn A. Watkins

President/Senior Economist

Technical Associates, Inc.

Consultant for the Indiana Office of Utility Consumer Counselor

Cause No. 45253

Duke Energy Indiana, LLC

October 30, 2019

Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 30th day of October to the following:

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