REVISED DIRECT TESTIMONY OF MARIA T. DIAZ
DIRECTOR, RATES AND REGULATORY PLANNING
ON BEHALF OF DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Maria T. Diaz, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana," "Applicant" or "Company") as Director, Rates and Regulatory Planning. Duke Energy Indiana is a wholly owned, indirect subsidiary of Duke Energy Corporation.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, RATES AND REGULATORY PLANNING.

A. I have responsibility for certain regulated rate matters involving Duke Energy Indiana, LLC ("Petitioner" or "Company"), including cost of service studies, rate administration, and rate tracker filings. I also administer rate issues for the Company's jointly owned facilities.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of the University of Indianapolis, holding a Bachelor of Arts Degree in Accounting. I also have a Master's in Business Administration from Butler University. I am a Certified Public Accountant in the State of Indiana. I was hired by the Company in 1997 as Supervisor of Fuels, Joint Ownership, and Trading Accounting. In 2000, I became Manager of Energy Trading Accounting. During 2005, I held the position of SEC Reporting Manager. Following the April 3, 2006 merger of Cinergy and Duke Energy, I assumed my current rates position with the Company.

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

A. My testimony in this proceeding presents the Company's jurisdictional separation study and retail cost of service study. I also present the implementation plan and tariff for the proposed decoupling rider. Petitioner's Confidential Exhibits 7-A (MTD) through 7-B (MTD), Confidential Exhibit 7-C (MTD), and Confidential Exhibit 7-D (MTD) relate to the jurisdictional study, Petitioner's Confidential Exhibits 7-E (MTD) through 7-G (MTD) (revised) pertain to the retail cost of service study, and Petitioner's Exhibits 7-H (MTD) and 7-I (MTD) are the proposed decoupling rider example and tariff, respectively. I also sponsor the related workpapers which satisfy the Minimum Standard Filing Requirements ("MSFR") to be filed with the case-in-chief, 170 IAC-1-5-15. (a) and (b). Those confidential workpapers are labeled JS1 through JS25, COSS1 through COSS244 (as revised), OM1 through OM6, RB1 through RB3, SW-RB1, SW-RB2, SW-EXP1 and SW-EXP2.

II. BACKGROUND

Q. WHAT IS A JURISDICTIONAL SEPARATION STUDY?

A. A jurisdictional separation study is a study to allocate assets, revenues, and expenses to customers that are not subject to this Commission's jurisdiction in this proceeding. In this filing, the jurisdictional separation study removes the Company's non-jurisdictional customers from the total Company amounts. After this is done, the remaining assets, revenues, and expenses, are all related to the provision of retail electric service and are the subject of this filing.

Q. WHAT IS THE PURPOSE OF A RETAIL COST OF SERVICE STUDY?

A. Once the retail assets, revenues, and expenses are identified by the jurisdictional separation study, a retail cost of service study allocates the assets, revenues, and expenses to the various rate classes. This study develops the proposed revenue levels for each retail rate schedule that is used in the rate design process as described by Duke Energy Indiana witness Mr. Jeffrey Bailey, Petitioner's Exhibit 8.

Q. HAS THE COMPANY NORMALLY PREPARED JURISDICTIONAL SEPARATION AND COST OF SERVICE STUDIES FOR ITS RATE PROCEEDINGS?

A. Yes, the Company has submitted jurisdictional separation studies and retail cost of service studies in each electric rate proceeding before this Commission.

Q. ARE YOU FAMILIAR WITH THE COST BASIS UPON WHICH JURISDICTIONAL SEPARATION STUDIES AND COST OF SERVICE STUDIES WERE PREPARED?

A. Yes, in all of these proceedings, the studies were developed on the basis of embedded or accounting costs.

Q. HAVE YOU PREPARED, OR HAD PREPARED UNDER YOUR SUPERVISION, A JURISDICTIONAL SEPARATION STUDY AND A RETAIL COST OF SERVICE STUDY FOR THE COMPANY FOR THE TWELVE CONSECUTIVE MONTHS ENDED DECEMBER 31, 2020, THE FORECASTED TEST PERIOD IN THIS PROCEEDING?

A. Yes, the studies were prepared on an embedded or an accounting cost basis, as applied to the forecasted test period of January 1, 2020 to December 31, 2020, and are attached as Petitioner's Confidential Exhibits 7-D (MTD) Schedule 1 and 7-G (MTD), Schedule 1 and 2 (revised).

Q. WHAT SOFTWARE APPLICATION WAS USED TO PREPARE THE JURISDICTIONAL SEPARATION AND COST OF SERVICE STUDIES?

A. Duke Energy Indiana used PowerPlan regulatory suite to support this base rate case proceeding. PowerPlan is a 3rd party application that was tailored to meet Duke Energy Indiana's requirements for the retail rate case filing and resulted in the creation of the "regulatory ledger tool." Some of the key features of the regulatory ledger tool include: (1) user-defined regulatory accounts that collect data from various sources, such as the PowerPlan asset module for assets and depreciation and has mapping functionality; (2) automated data integration such as uploads from Utilities International ("UI") Planner, which is the software designed by Utilities International used by the Company for its budgets, and the capital forecast into the regulatory ledger tool; (3) case management, which results in the creation of multiple cases for different scenarios; (4) flexibility on the type of test period selected such as the ability to support historical and forecasted test periods; (5) separations/allocations to determine jurisdictional and class of service costs and revenue requirements including use of multi-tiered allocations, dynamic allocations (allocations dependent on other balances), and specific assignment; and (6) multiple output reports and queries in a Microsoft Excel format.

Q. PLEASE BRIEFLY EXPLAIN THE GENERAL DESIGN AND TERMINOLOGY USED IN THE TEMPLATES CONTAINED IN THE POWERPLAN APPLICATION TO PRODUCE THE STUDIES.

A. The design template was setup with the following structure:

Function, which assigns data into function categories (Production, Transmission, Distribution, and Customer) and sub-functions. The function data populates the *Separation* step, wherein the data is separated between a Steam Customer and all other Electric customers. The electric data feeds and populates the *Jurisdiction Separation* step, wherein the data is separated between Indiana Retail and Wholesale. The Indiana Retail data feeds and populates the *Retail Rate Codes*, wherein the data is separated by each rate schedule and grouped into customer classes for rate design processing. I describe these steps in more detail later in my testimony.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S ORDER IN CAUSE NO. 42873, ("DUKE MERGER PROCEEDING") RELATING TO COINCIDENT PEAK ("CP") ALLOCATION METHODOLOGY.

A. In that order, the Company agreed to in its next proceeding for the setting of retail electric base rates and charges, to provide its cost of service and rate design for production plant using a 4 CP methodology. The Company agreed to fully support the 4 CP methodology for production plant in the elements of the proceeding. The Company also is to provide a cost of service and rate design utilizing the 12 CP methodology for production plant, for comparison purposes. The 12 CP method of allocation was approved at least 13 times since 1971 in the Company's retail rate case proceedings. The OUCC agreed to not oppose the 4 CP methodology for production plant in the Company's next proceeding for the setting of retail electric base rates and charges.

Q. HOW HAS THE COMPANY COMPLIED WITH THE ORDER IN CAUSE NO. 42873 RELATING TO THE CP ALLOCATION METHODOLOGY?

A. In its retail cost of service study, the Company performed allocations for production plant using both a 4 CP and 12 CP methodology to its rate schedules. The Company also performed allocations for transmission plant to synchronize with the production methodology, such that the 4 CP for production plant was used with the 4 CP for transmission plant, while the 12 CP for production plant was used with the 12 CP for transmission plant.

Q. BEFORE PREPARING THE JURISDICTIONAL SEPARATION AND COST OF SERVICE STUDIES, WHAT STEPS WERE PERFORMED?

A. The process of functionalization and classification was performed. This is the same methodology utilized by the Company in previous rate cases.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION AND CLASSIFICATION PROCESS.

A. Functionalization is the process by which costs are separated according to the major electric system functions of production, transmission, distribution, and customer costs. In general, the functionalized costs as reported in the FERC Uniform System of Accounts are used, but certain accounts, such as general and intangible plant are not initially assigned to the major functions but functionalized according to other related costs so that they can be properly classified and allocated. A similar example to general plant is administrative and general costs that are allocated based on salaries and wages to the major functions.

Production refers to all production facilities including steam generation, hydraulic generation, and other production necessary to integrate that generation into the power supply system and deliver it to the bulk transmission system.

Transmission refers to costs associated with the high voltage system utilized for the transmission of power to interconnected customers and includes transmission substations and lines necessary to integrate the Company's sources of power, whether owned or purchased, into the power supply system. The investment in the transmission system for instance, was distinguished in more detail as noted in the chart below.

Distribution refers to the facilities required to connect the ultimate customer to the transmission system and was also distinguished in the detail noted in the chart below.

The customer function includes the costs associated with providing meter reading, billing, and customer services.

In the regulatory tool, within the major functions described, the Company assigned "function targets" (or a sub-function) by each regulatory ledger account to assist with rate design and reporting.

Table 1

Function	Function Target
Production	Production Demand Production Energy
Transmission	Transmission Step-ups Transmission Bulk Transmission Common Transmission Sole Use Other Transmission Sole Use Special Property Transmission – Distribution Use
Distribution	Distribution Sub Facilities (Step-downs) Distribution Overhead (OH) Primary Facilities Distribution Underground (UG) Primary Facilities Distribution Subs Special Property Distribution Primary Meter Distribution Meter Maintenance Distribution Meter Operations Distribution Line Transformer Connection Distribution OH Secondary Connection Distribution UG Secondary Connection Distribution Secondary Meter Distribution Street Lighting Distribution – Transmission Meter Distribution Services Distribution Outdoor Light
Customer Service	Distribution Customer Installation Customer Accounts Customer Service and Information

The assignment to function targets occurred via creation of allocator factors (*i.e.* percentages) that assigned regulatory ledger accounts to the sub-functions. The percentages were developed per internal data request responses, internal studies, or direct assignment.

Classification also occurred wherein the functionalized costs are designated as being demand, energy, or customer related. Demand and customer related costs are costs that are incurred regardless of the level of energy sales and that vary with the demand imposed by the customer and related to the number of customers served. Examples of such costs are production, transmission, and the major portion of the distribution plant and related expenses. Variable costs are those which vary with the level of energy produced and the number of kilowatt hours used by the customer. Fuel expense is an example of this type of cost. Meters are an example of a cost whose level is affected by the number of customers served.

Below is a summary of the classification:

Table 2

Function	**Classification**
Production	Demand, Energy
Transmission	Demand
Distribution	Demand
Customer Service	Customer

Q. PLEASE DESCRIBE THE ALLOCATION OF SUPERVISION, ENGINEERING, AND MISCELLANEOUS EXPENSES ("SE&M")

A. The SE&M from the forecast were allocated to the associated expenses that such SE&M supported at the FERC account level. This was done in a two-step process and the results were then input in the regulatory ledger tool; an allocation exclusive of the pro-forma adjustments and then the allocation with the pro-forma adjustment. At each step, the SE&M was zeroed and the SE&M costs reassigned to the associated expenses the SE&M were supporting based on the proportion of the associated expenses. Confidential MSFR Workpaper OM1-MTD is filed as support.

Q. HOW DOES THE SE&M PROCESS RELATE TO THE FUNCTIONALIZATION AND CLASSIFICATION YOU DESCRIBED EARLIER?

A. The ending expense amounts that result after the SE&M process advance for functionalization and classification in the jurisdictional separation study. Confidential MSFR Workpaper OM2-MTD illustrates the production, operation, and maintenance balances and lists the allocators applied to determine functional and classified expense amounts by account. Confidential MSFR Workpaper OM3 – MTD shows the allocation of transmission operation and maintenance expenses to functional categories and lists the allocators applied by account. Confidential MSFR Workpaper OM4–MTD shows the allocation of distribution operation and maintenance expenses to functional categories and lists the allocators applied by account. Confidential MSFR Workpaper OM5–MTD shows the allocation of administrative and general expenses to functional categories based on a salaries and wages allocator calculation performed on Confidential MSFR Workpaper SW-EXP1–MTD and SW-EXP2 -MTD. The detailed MSFR workpapers referenced here are summarized on Confidential MSFR Workpaper OM6-MTD, Summary of Operation and Maintenance Expense and Pro-Forma Adjustment.

Q. WHAT ADDITIONAL WORKPAPERS WERE PREPARED TO ILLUSTRATE THE ASSIGNMENT OF PLANT-IN-SERVICE AND ACCUMULATED DEPRECIATION FOR THE FUNCTIONS WHICH HAD MULTIPLE FUNCTION TARGETS?

A. Confidential MSFR Workpaper RB-1 MTD, shows the allocators applied to each transmission rate base account after the walk-up of the balances performed by witness Ms. Douglas. Confidential MSFR Workpaper RB-2 MTD, shows the allocators applied to each distribution rate base account after the walk-ups of the balances done by witness Ms. Douglas, and Confidential MSFR Workpaper RB-3 MTD, shows the application of the salaries and wages allocator per MSFR Confidential Workpaper SW-RB1 MTD and SW-RB2 MTD to general plant rate base.

After the functionalization and classification process, the forecasted amounts advance to the jurisdictional separation study for further cost allocation and form the basis on which to allocate the different costs to the Company's classes of customers in the cost of service study.

III. <u>JURISDICTIONAL SEPARATION STUDY</u>

Q. WHAT IS THE PROCESS USED IN PREPARING THE JURISDICTIONAL SEPARATION STUDY?

A. The Company's forecast, which is supported by Duke Energy Indiana witness Mr. Christopher Jacobi is the starting point of information for the functionalization process previously described. Furthermore, the Company's forecast is the starting point for the jurisdictional separation study to which *proformas* and ratemaking adjustments proposed by the Company's witnesses in this case were prepared. Then, the following step that occurs is the segregation of the Company's customers into three main categories: The categories are: (i.) one customer who purchases high pressure steam from the Company's Cayuga Generating Station (International Paper), (ii.) wholesale electric customers who purchase firm power from the Company and resell it to their ultimate customers or their members, and the remainder, (iii.) retail electric customers who purchase power from the Company as ultimate consumers.

Q. IS THE COST TO PROVIDE THE STEAM SERVICE YOU PREVIOUSLY MENTIONED IDENTIFIED SEPARATELY IN THE JURISDICTIONAL SEPARATION STUDY?

A. Yes, it is. International Paper, which purchases high-pressure steam from Duke Energy Indiana's Cayuga Generating Station is identified as an individual customer. This portion of the jurisdictional study is referred to as the steam study.

Q. PLEASE IDENTIFY THE DOCUMENTS THAT HAVE BEEN MARKED AS PETITIONER'S CONFIDENTIAL EXHIBITS 7-D (MTD) AND CONFIDENTIAL EXHBIT 7-C (MTD).

A. Petitioner's Confidential Exhibit 7-D (MTD) Schedule 1 is the result of the steam study. Schedule 2 is the allocation of the Cayuga Generating Station plant investment, regulatory assets, prepaid pension asset, fuel stockpile, and materials and supplies to Steam Service and Electric Utility. Schedule 3 shows the allocation of materials and supplies by type. Schedule 4 is the allocation of the Cayuga Generating Station operation and maintenance expenses, administrative and general expenses, depreciation and amortization, and taxes other than income taxes to Steam Service and Electric Utility. The allocations were made using the assigned peak demand responsibility, developed on Schedule 1 of Petitioner's Confidential Exhibit 7-C (MTD), assigned equivalent net generation (demand basis), developed on Schedule 2 of Petitioner's Confidential Exhibit 7-C (MTD), assigned megawatt-hour responsibility, developed on Schedule 3 of Petitioner's Confidential Exhibit 7-C (MTD), assigned equivalent net generation (megawatt-hour basis), developed on Schedule 4 of Petitioner's Confidential Exhibit 7-C (MTD). The assignment at the separation (steam) target occurred via creation of the allocator factors or percentages which were assigned by regulatory ledger account. The percentages were developed based on data request responses, internal studies, or direct assignment. Confidential MSFR Workpaper JS18-21 MTD is the listing of regulatory general ledger accounts and the respective allocator used per each account at the steam study step.

Q. WHAT IS THE NEXT STEP IN PREPARING THE JURISDICTIONAL SEPARATION STUDY?

A. The next step is the development of the demand and energy allocators for the Company's non-jurisdictional customers mentioned earlier.

Q. PLEASE EXPLAIN THE WHOLESALE CUSTOMERS' AGREEMENTS THAT WERE CARVED OUT AS A SEPARATE CATEGORY.

A. The Company provides electric service through the generation and sale of electricity to native load wholesale customers. The Company has generally provided these wholesale electric customers with their full electric load requirements or with supplemental load requirements when the customer has other sources of electricity. The native load wholesale electric service reported as a separate category in this proceeding is provided under long-term power production contracts using market-based pricing under Duke Energy Indiana's market-based authority. The native load wholesale contracts include both energy and demand charges. Contractual amounts owed are trued-up annually based on incurred production costs in accordance with costs reported in the FERC Form No. 1, the Company's supporting accounting records, and the specific customer's actual peak demand and usage.

Q. WHO REGULATES DUKE ENERGY INDIANA'S CONTRACTS FOR WHOLESALE ELECTRIC SERVICE?

A. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over Duke Energy Indiana's agreements with its wholesale customers.

Q. PLEASE EXPLAIN HOW THE WHOLESALE CUSTOMERS WERE ACCOUNTED FOR IN THE JURISDICTIONAL SEPARATION STUDY.

A. The aforementioned long-term power production contracts are considered firm, native load sales; as such, production costs and related production expenses were allocated to these wholesale customers in the study. There is one particular wholesale 100 MW contract that is considered a short-term bundled non-native contract that was not allocated costs in the jurisdictional separation study due to the proposed sharing of the contract in Standard Rider No. 70, as further described in the Direct Testimony of Company witness Mr. John A. Verderame, Petitioner's Exhibit 23.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S CONFIDENTIAL EXHIBIT 7-A (MTD) AND 7-B (MTD).

A. Petitioner's Confidential Exhibit 7-A (MTD) is a two-page summary that shows the summarization of the wholesale production demand allocators used in the jurisdictional separation study. Per the Company's 2018 Fall load forecast, the production system peak day and time and the corresponding coincident demands by retail, wholesale, and company use for the test period were provided as reflected on Confidential MSFR Workpaper JS-1 (MTD). Page 1 and 2 of Petitioner's Confidential Exhibit 7-A (MTD) develop the wholesale customer group's twelve-month average coincident peak electricity demands and percentage of the production system ("wholesale (production) demand allocator"). The load forecast reported the demands at the busbar level of the generating facilities. Per the Company's load forecast, the megawatt-hour ("MWH") usage by retail, wholesale, and Company use for the 2020 test period was provided as reflected on Confidential MSFR Workpaper JS-2 (MTD). Page 1 and 2 of Petitioner's Confidential Exhibit 7-B (MTD) develops the wholesale customer group's twelve-month megawatt-hour ("MWH") and percentage of the production system ("wholesale (production) energy allocator"). The load forecast reported the usage at the busbar level of the generating facilities. Confidential MSFR Workpapers JS-1 and JS-2 (MTD) are filed that detail customer-specific demands and usage by each wholesale customer.

In summary, Petitioner's Confidential Exhibits 7-A (MTD) and 7-B (MTD) developed the system peak demand (and usage) and the applicable wholesale customers' share of the system peak (and usage), with the remainder being the retail portion of Duke Energy Indiana's total system demand (and usage), which represents the retail customers' portion of the maximum electricity load and usage imposed on Duke Energy Indiana's electric system. The wholesale demands and usage for the forecasted 2020 period approximated 8%, which approximates the same percentage from the last base rate case.

Q. HOW WERE THE WHOLESALE PRODUCTION DEMAND AND ENERGY ALLOCATORS USED IN THE JURISDICTIONAL SEPARATION STUDY?

A. The allocators or percentages were applied to function target amounts in the test period, which were production-related, and which amounts were not already determined to be 100% retail or 100% wholesale, based on the specific regulatory ledger account. The function target is the combination of the initial regulatory general ledger account and the function (*i.e*. production). Specifically, the production-demand allocator was then applied to total Company production-demand regulatory ledger amounts and the production-energy allocator was then applied to total Company production-energy regulatory ledger amounts to determine the wholesale carve-outs of the total Company amounts.

Q. WHAT OTHER ALLOCATORS WERE USED IN THE JURISDICTONAL STUDY?

A. There was the 100% assignment to retail or 100% assignment to wholesale, depending on the regulatory ledger account. For example, sales for resale were assigned as 100% wholesale, while retail sales were assigned 100% retail.

Q. PLEASE EXPLAIN OTHER COST ALLOCATION CONSIDERATIONS AT THE JURISDICTIONAL SEPARATION STUDY STEP.

A. The other cost allocation consideration was to allocate the fixed or demand-related costs based on demand allocation factors, the variable or energy-related costs based on the energy allocation factors.

Q. HOW WERE OTHER WHOLESALE REVENUES ADDRESSED IN THE JURISDICTIONAL STUDY?

A. The Company receives revenues from two wholesale customers for usage of Duke Energy Indiana's local facilities (*i.e*. distribution substations) as well as receives revenues from the Midcontinent Independent System Operator, Inc. ("MISO") for usage of Duke Energy Indiana's transmission system, such revenues were included in the development of the forecast for this proceeding. The forecasted revenues were assigned 100% to retail as the forecasted costs to supply the wholesale distribution and transmission services were assigned 100% to retail.

Q. PLEASE EXPLAIN THE TRANSMISSION-RELATED OWNERSHIP ARRANGEMENT CURRENTLY IN EFFECT AND APPLICABILITY TO WHOLESALE PARTNERS AND HOW WAS SUCH ARRANGEMENT ADDRESSED IN THIS PROCEEDING?

A. Duke Energy Indiana, WVPA, and IMPA continue their arrangement under the Transmission and Local Facilities Ownership, Operation, and Maintenance Agreement, ("T&LF Agreement") whereby the parties own the Joint Transmission System ("JTS") in Indiana and have rights to the JTS. The T&LF Agreement provides for the aforementioned parties to jointly own transmission plant, based on the loads of the parties, rather than Duke Energy Indiana owning 100% of the facilities and WVPA and IMPA paying for the facilities through rates. Even though each party owns specific pieces of property, such ownership provides each party with an individual ownership interest, as tenants-in-common, in all rights to use, output, and capacity of the JTS. The T&LF Agreement further provides for a reconciliation each calendar year to compare each party's actual ownership in the joint transmission system to its proportionate share requirements based on loads for such calendar year. Any party or parties who are under their proportionate share shall compensate the party or parties who are over their proportionate share by paying fixed charges based on terms of the T&LF

Agreement. The parties to the T&LF Agreement who are the primary users of specific local facilities generally are also owners of the facilities. In the case of joint use of a facility by the parties, the owning party receives compensation through payment of charges based on the parties' loads imposed on such specific facility. Because WVPA and IMPA own transmission and local facilities and pay for their allocated share of operating and maintenance expenses through provisions of the T&LF Agreement, Duke Energy Indiana's share of its investment in such facilities and related operation and maintenance expenses including administrative and general costs, and including the results of the reconciliation feature, are allocable to retail customers in the jurisdictional separation study. Duke Energy Indiana's forecasted JTS revenues were assigned 100% to retail, as the forecasted costs for Duke Energy Indiana's share of JTS transmission services were assigned 100% to retail.

Q. WHAT OTHER GENERATION STATION OWNERSHIP ARRANGEMENTS ARE CURRENTLY IN EFFECT AND APPLICABLE RELATING TO WHOLESALE PARTNERS AND HOW WERE SUCH ARRANGEMENTS ADDRESSED IN THE PROCEEDING?

A. Duke Energy Indiana, WVPA, and IMPA continue their arrangement in Gibson Unit 5 whereby the parties are entitled to their respective shares of generating capacity and output of Unit 5 equal to their respective ownership interests. Duke Energy Indiana specifically owns 50.05% of Gibson Unit 5. Similarly, Duke Energy Indiana owns 62.5% of Vermillion Generating Station with WVPA owning the remainder. Capital costs and operation and maintenance costs are divided based on ownership interests. Thus, the net plant in-service and the associated operations and maintenance expenses including administrative and general costs, allocated to Duke Energy Indiana in the forecast for this proceeding excludes WVPA's and IMPA's shares for Gibson Unit 5 and WVPA's share of Vermillion station. Further, Duke Energy Indiana has a 50 MW contract with a customer associated with Henry County Generating Station, which reduces the capacity available for Duke Energy Indiana customers. This 50MW has been removed from the Company's rates by way of *pro forma* as discussed in the direct testimony of Ms. Sieferman and the sales revenue assigned to wholesale.

Q. WHAT IS THE NEXT STEP IN COMPLETION OF THE JURISDICTIONAL SEPARATION STUDY?

A. After the allocator assignments are completed by each regulatory ledger account, the next step is to compute the allocation calculation that allocates the plant costs and expenses to the aforementioned power production customers and the one steam customer. The purpose behind this allocation is to separate out the customers and associated costs that are not part of this proceeding. Thus, the aforementioned customers that were treated as wholesale and the one steam customer are considered non-jurisdictional for purposes of this proceeding, while the retail electric customers and other retail assignments are the jurisdictional customers and activity for purposes of this proceeding.

Q. WHAT METHODOLOGY WAS USED TO ALLOCATE PRODUCTION AND PRODUCTION RELATED PLANT COSTS AND EXPENSES IN THE JURISDICTIONAL SEPARATION STUDY?

A. The 12 CP method was used for these allocations in Petitioner's Confidential Exhibit 7-D (MTD) Schedule 2.

Q. HAS DUKE ENERGY INDIANA UTILIZED THIS 12 CP METHODOLOGY IN PREVIOUS RATE FILINGS?

A. Yes. As I previously mentioned, Duke Energy Indiana has used the 12 CP method in at least 13 filings with the Commission since 1971. The Company also adopted this approach for setting of rates in the wholesale resale market. Duke Energy Indiana's historical wholesale formula production rates described previously are priced annually on a 12 CP per the production peaks reported in the FERC Form 1. Similarly, review of the wholesale demands for the forecasted test period show demands that lie within a narrow range of outcomes; *i.e.*, the annual load shape is not spiky.

Q. PLEASE CONTINUE DISCUSSING PETITIONER'S EXHIBT 7-D (MTD) AS IT RELATES TO WHOLESALE.

A. Schedule 1 of Petitioner's Confidential Exhibit 7-D (MTD) identifies the wholesale portion of the jurisdictional study separately in the wholesale column. Schedule 2 is the allocation to wholesale of the following assets: production-related plant investment, prepaid pension asset, fuel stockpile and emission allowances, and production-related materials and supplies. Schedule 3 is the allocation of materials and supplies by type. Schedule 4 is the allocation of production-related operations and maintenance and administrative and general expenses, depreciation and amortization, and taxes other than income taxes. Confidential MSFR Workpaper JS22-25 MTD is the listing of regulatory general ledger accounts and the respective allocator used per each account at the wholesale step.

Q. PLEASE CONTINUE DISCUSSING PETITIONER'S CONFIDENTIAL EXHIBIT 7-D (MTD) AS IT RELATES TO TAXES ALLOCATED ACROSS THE STUDIES.

A. Schedule 5 shows the allocation of both Federal and State deferred income taxes and the investment tax credit. The allocation of current Federal and State income tax provisions and the calculated current Federal and State taxes are shown on Schedule 6, page 1 and 2.

IV. <u>RETAIL COST OF SERVICE STUDY</u>

Q. ONCE THE JURISDICTIONAL SEPARATION STUDY IS COMPLETE, WHAT IS THE NEXT STEP?

A. After completion of the jurisdictional separation study, the Company can complete the cost of service study for its retail customers using the total retail customer amounts from the jurisdictional separation study.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S CONFIDENTIAL EXHIBIT 7-E (MTD).

A. Petitioner's Confidential Exhibit 7-E (MTD) is a summary of the major allocation factors by rate group for Duke Energy Indiana's retail electric customers, using historical studies to develop the factors. The development of these major factors is the first step in the completion of the retail cost of service study. The five major allocation factors shown are:

(1) Allocated Share of System Peak – average of the 4 highest coincident peaks (in kilowatts) at the generating station in accordance with the Commission's Order in Cause No. 42873;

(2) Megawatt-hour (MWH) Plant Output Adjusted for Duke Energy Indiana use at the generating station;

(3) Non-coincident Peak Demands (in kilowatts) at the customer's meter.

(4) Diversified Class Demand (in kilowatts) at the input to the Primary Distribution System; and

(5) Delivery point number of customers.

Q. PLEASE EXPLAIN WHAT THE TERMS "COINCIDENT PEAK DEMAND", "DIVERSIFIED CLASS DEMAND", AND "NON-COINCIDENT PEAK DEMAND" REPRESENT.

A. The "coincident peak demand" is the electricity demand of the various customer classes and rate groups at the time of the Duke Energy Indiana demand for a given month. The "diversified class demand" is the peak electricity demand of the class on the distribution system, regardless of when Duke Energy Indiana's electricity demand for the month occurs. Thus, the "diversified class demand" accounts for the different load characteristics and the diversity of class demands on the distribution system. The "non-coincident peak demand" is the highest peak electricity demand for a customer in a given period, regardless of the time of occurrence.

Q. PLEASE EXPLAIN HOW THE MWH ALLOCATOR WAS DEVELOPED.

A. The first step is the accumulation of kilowatt-hours by month for each rate group. The rate group information is further broken down by voltage level, secondary (under 600 volts), primary (600 volts to 34,500 volts), and transmission (over 34,500 volts) based on service voltage and then by metered voltage. The transmission service customers are also broken down between bulk (138,000 volts or higher) and common (69,000 volts). Next, the metered kilowatt-hour data for the twelve-month period ended June 30, 2018 was used to develop the kilowatt-hour requirement at the generating station by rate group.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE BULK TRANSMISSION SYSTEM AND THE COMMON TRANSMISSION SYSTEM.

A. The bulk transmission system is comprised of transmission facilities with the voltage of 138,000 volts or higher, whereas the common transmission system is comprised of transmission facilities with a voltage of 69,000 volts. The transmission facilities are discussed in more detail in the direct testimony of Duke Energy Indiana witness Mr. Timothy A. Abbott.

Q. HOW WAS THE "ALLOCATED SHARE OF SYSTEM PEAK", "MAXIMUM NON-COINCIDENT DEMANDS", AND "DIVERSIFIED CLASS DEMAND" DEVELOPED?

A. The kilowatt data is broken down in the same groups as the kilowatt-hour data previously discussed. The respective demands by type above were compiled and supplied as follows by Mr. Bailey:

(1) The demands for all customer classes and rate groups that have non-load profile meters that are below the 500 kilowatt level per customer level, were obtained from a load research program conducted by the Duke Energy Indiana load research department. Statistical analysis of the load research data enables the Company to estimate the kilowatt demands and kilowatt-hour usage for these customer classes and rate groups with a relative precision of plus or minus 10% and at a 90% confidence level. The twelve-month period ended June 30, 2018 was the population used.

(2) The respective demands by type above for the rest of the retail customers were obtained from the actual metered billing information, also using a twelve-month period ended June 30, 2018 for the population and adjusted to the generating station level.

Q. YOU STATED PREVIOUSLY THAT WITHIN THE COST OF SERVICE STUDY, YOU PREPARED THE ALLOCATED SHARE OF SYSTEM PEAK DEMANDS ON A 4 CP BASIS. DID YOU ALSO PREPARE A 12 CP VERSION?

A. Yes, Confidential MSFR Workpaper COSS-204 (MTD) is a summary of the 12 CP Allocated Share of System Peak provided for comparison purposes per Order in Cause No. 42873. The impact of the 12 CP factors resulted in minor proposed rate increase differences across the major classes (in the 2% range) from the 4 CP factors.

Q. PLEASE GENERALLY DESCRIBE YOUR UNDERSTANDING OF THE 4 CP DEMANDS SUPPLIED BY MR. BAILEY, AND THE RELEVANCE OF THE FERC ALLOCATION GUIDELINES FOR PRODUCTION AND TRANSMISSION-DEMAND RELATED COSTS.

A. The 4 CP demands supplied by Mr. Bailey were the average of the maximum retail demands for the historical twelve-month period ended June 30, 2018. The 4 CP peak period average included the months of August 2017, September 2017, January 2018, and June 2018. From this historical data, Mr. Bailey supplied the retail demands by detailed rate code as included in the Cost of Service Study. Although there is not a steadfast rule for determining which demand allocation is appropriate, as a frame of reference, the FERC primarily relies on three system demand tests when determining which coincident peak method is supported by the record. FERC applies established thresholds to the results of these tests to assess whether a customer's allocation of the demand costs should be based on a 12 CP or another methodology. The first test, the "Low to Annual Peak" test, calculates the relationship of the lowest monthly peak as a percentage of the annual peak. Under the Low to Annual Peak test, a range of sixty-six (66%) or higher supports the use of a 12 CP method. The second test is the "Average to Annual Peak" test, which computes the average of the twelve-monthly peaks as percentage of the annual peak. Under the Average to Annual Peak test, a range of eighty-one (81%) or higher supports the use of the 12 CP method. Duke Energy's Indiana's monthly load characteristics for the twelve-month period ended June 30, 2018 meet the first and second test. The third test is the "On and Off Peak" test, which compares the average of the system peaks during the peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. Under the On and Off-Peak test, a 19% or less difference between these two figures supports the use of the 12 CP method (using the respective months as the peaks and the valleys in the calculation) and likewise, the same threshold applies to the 4 CP variation (using the respective 4 CP months as the peak and the 8 CP months as the valley). Duke Energy Indiana's load characteristics for the twelve-month period ended June 30, 2018 also satisfy the third test. However, ultimately, as Mr. Bailey discusses, the differences between 4 CP and 12 CP did not materially alter any of the rate designs.

Q. PLEASE EXPLAIN HOW THE DELIVERY POINT NUMBER OF CUSTOMERS WAS DEVELOPED.

A. The delivery number point number of customers was sourced from the Company's billing system with adjustments for the average number of customers, using a twelve-month period ended June 30, 2018.

Q. PLEASE EXPLAIN THE APPROACH UTILIZED IN THE COMPANY'S COST OF SERVICE STUDY FOR DETERMINING THE COMPANY'S COST OF SERVICE FOR ITS RETAIL ELECTRIC SALES.

A. The study is completed using equitable and reasonable allocation methodologies. The methods for allocation used in this proceeding were not changed from the methods used in Duke Energy Indiana's last retail base rate case. The allocation of investment, operating expenses, and taxes to the retail customer classes and rate groups produces Duke Energy Indiana's retail revenue requirement. There are four (4) major classifications of functionalized costs and allocation factors:

(1) Demand-related production and transmission costs that are allocated based on the customers' coincident peak demands – their electricity demand that occurs at the time of the Duke Energy Indiana, as adjusted to the busbar of the generating plant.

(2) Energy-related production costs that are allocated based on the customers' energy requirements, as adjusted to the busbar level of the generating plant.

(3) Facility-related distribution costs that are allocated based on the customers' diversified class electricity demand, non-coincident peak electricity demands, or directly assigned to a customer.

(4) Connection-related costs that are allocated based on non-coincident peak demands or on the number of customers or delivery point number of customers.

Q. PLEASE PROVIDE EXAMPLES OF EACH OF THE FOUR (4) CLASSIFIED COSTS AT THE RETAIL COST OF SERVICE STUDY LEVEL.

A. An example of demand-related costs would be the investment in the transmission system and the corresponding operation and maintenance expenses. The sizing of such facilities is determined by the expected load of Duke Energy Indiana's customers on the facility; it is not related to the energy requirement or the number of customers.

As mentioned previously, fuel expense and fuel stockpile are common examples of energy-related costs. These items are dependent upon the amount of energy consumed, not the customers' demands or the number of customers.

An example of a facility-related cost would be the investment and expenses for distribution substations. Duke Energy Indiana's substations are designed to meet the expected Duke Energy Indiana load, and thus, are allocated based on the customers' diversified class electricity demand.

Connection-related costs include investment and expenses for electric meters and customer accounts. These items are related to the number of customers or to the customers' non-coincident peak electricity demand; the facilities are sized for the individual peak electricity loads.

Q. DOES DUKE ENERGY INDIANA'S FORECAST REFLECT THE ALLOCATION OF THE VARIOUS ACCOUNTS TO THE FOUR (4) MAIN CATEGORIES OF CLASSIFIED COSTS?

A. The accounts in the forecast were the starting point for the classification but when certain accounts are related to more than one of the classifications, specific analysis, studies, and judgment are used to separate the individual components.

An example of such separation is the breakdown of power production operation and maintenance ("O&M") between demand and energy components. The demand and energy components of Duke Energy Indiana's total power production expenses were determined based on a multi-year, historical study performed by the Duke Energy Indiana engineering department per the direction of Duke Energy Indiana witness Mr. Keith Pike. The engineering department performed an analysis of the total operation and maintenance expenses to determine the demand and energy components. From that analysis, the percentages were input into the regulatory ledger tool by forecasted account, and the tool calculated the demand and energy account balances for further processing in the Cost of Service study.

Another example is the separation of distribution line investment between primary and secondary lines performed by the Duke Energy Indiana customer delivery department. A listing of the equipment contained in the plant records was analyzed and the property units were split by primary and secondary voltages.

Q. DID THE COMPANY DIRECT ASSIGN COSTS TO SPECIFIC RATE CLASSES?

A. Yes, facilities and equipment constructed and used by a specific customer were direct assigned and allocated to a single class, or even a single customer (*i.e.*

specific property). An example of such a facility is a distribution substation that is dedicated exclusively to serving a specific customer. The other types of specific property are transmission radial tap lines and distribution substations.

Q. HOW WAS SPECIFIC PROPERTY IDENTIFIED AND ADMINISTERED IN THE RETAIL COST OF SERVICE STUDY?

A. The Company's billing system was used to compile a specific property listing, that identified retail customers served directly at a transmission voltage or from a dedicated substation at a primary voltage. The specific property listing was provided to the Company's large business account representatives for review, verification, and updating. Corresponding single-line schematics were also reviewed to ensure the configuration of the facility or equipment was for a specific customer and not a networked facility or line. After the specific property was identified and the cost developed using the fixed asset system which also included developing a walk-up of fixed assets as of December 31, 2018 through the end of the forecasted test year as described by Company witness Ms. Diana Douglas, the assignment of the specific property to the specific customer or single class was accomplished by use of specific property allocators. Confidential MSFR Workpapers COSS 174-176 (MTD) is the listing of the specific property by type as of December 31, 2018 that was used as inputs to the walk-ups supported by Ms. Douglas. Confidential MSFR Workpaper COSS-171 (MTD) is the specific property assignments, which were input into the regulatory ledger tool for cost assignment.

Q. WHAT IS THE NEXT STEP IN THE COMPLETION OF THE RETAIL COST OF SERVICE STUDY?

A. Once the allocation factors are complete, the actual allocation of plant investment and expenses can be performed. The allocation factors are applied to the rate base investment and expenses derived from the jurisdictional separation study discussed previously. The allocation factors developed are included in Confidential MSFR Workpaper COSS-178 (MTD), which shows the name of the allocation factor and the percentages assigned by rate code.

Q. PLEASE IDENTIFY THE DOCUMENT MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S CONFIDENTIAL EXHIBIT 7-F (MTD) SCHEDULE 1.

A. Petitioner's Confidential Exhibit 7-F (MTD) Schedule 1 is the resulting allocation of the *pro forma* original cost depreciated plant as of December 31, 2020, to the retail customers by rate group. This exhibit shows the plant by major functional component, and segregates materials and supplies. There were no material changes in allocation methodologies from those approved in the last retail rate case for rate base.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S CONFIDENTIAL EXHIBIT 7-F (MTD) SCHEDULE 2.

A. Petitioner's Confidential Exhibit 7-F (MTD) Schedule 2 is the resulting allocation of the *pro forma* operating expenses, excluding income taxes for the test period ended December 31, 2020, to the retail customers by rate group. The exhibit shows the functionalized components of operation and maintenance expense, administrative and general expense, revenue credits, payroll related taxes, property related taxes, and depreciation expense. There were no material changes in allocation methodologies from those approved in the last retail rate case for operating expenses.

Q. WHAT IS THE NEXT STEP IN THE COMPLETION OF THE RETAIL COST OF SERVICE STUDY?

A. The last step in the retail cost of service study involves the allocation of deferred income taxes and investment tax credits (net). Following these allocations, the current State and Federal income taxes is calculated. Net operating income is then calculated by subtracting the operating expenses (including the State and Federal income taxes), from the operating revenues received from each retail rate group.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S CONFIDENTIAL EXHIBIT 7-G (MTD) SCHEDULE 1.

A. Petitioner's Confidential Exhibit 7-G (MTD) Schedule 1 is the summary of the retail cost of service study at present rates including *pro formas*. This schedule shows the original cost depreciated plant, electric operating revenues, total operating expenses, net operating income, and rate of return by retail rate group.

Q. REFERRING YOU TO PETITIONER'S CONFIDENTIAL EXHIBIT 7-D (MTD) SCHEDULE 1, WHICH FIGURES WERE USED IN THE ANALYSIS OF THE COMPANY'S COST OF SERVICE TO ITS RETAIL CUSTOMERS?

A. The last column of Petitioner's Confidential Exhibit 7-D (MTD) Schedule 1 labeled "Total Retail Customers" was used in the retail cost of service study, which is the summarized version of the Petitioner's Confidential Exhibit 7-G (MTD) Schedule 1, as previously identified.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S CONFIDENTIAL EXHIBIT 7-G (MTD) SCHEDULE 2 (REVISED).

A. Petitioner's Confidential Exhibit 7-G (MTD) Schedule 2 (revised) shows: (1) the results of the 4 CP retail cost of service study in Columns A through G; (2) the Company's proposal to more fully reflect its cost of service in Columns H thru J; (3), the proposed rate increase in Column K; and (4) the adjusted results of the retail cost of service study, after reflecting the proposed 5.1 percent subsidy/excess reduction (discussed below), and the resulting, net proposed rate increase percentages in Columns L through P. The drivers for the overall 15.43%[1] proposed rate increase reflected on this schedule are discussed by Mr. Davey.

Q. WHAT IS SUBSIDY/EXCESS?

[1] Does not include the impacts of Utility Receipts Tax

A. Subsidy/excess refers to the rate of return variability among the various rate groups under present rates. As Mr. Davey discusses, the concept of gradualism provides that the variability be reduced across the rate groups with each rate case so as to converge the rate groups closer to the average rate of return while being cognizant of how the reduction in the subsidy/excess in a given rate case impacts the proposed rate increase across the classes.

Q. PLEASE DISCUSS THE SUBSIDY/EXCESS REVENUES BETWEEN RATE GROUPS AND HOW ITS PROPOSED MOVEMENT WAS USED IN THIS PROCEEDING.

A. A review of the four major rate groups shows the variation in current levels of subsidy/excess revenues. The amounts below, are from Columns H and I (I divided by H) of Petitioner's Confidential Exhibit 7-G (MTD) Schedule 2 (revised):

Rate RS:	8.94% Subsidy
Rate CS:	1.12% Excess
Rate LLF:	0.51% Excess
Rate HLF:	12.68% Excess

The amount of subsidy/excess reduction was determined based on the Company's strategic objectives as explained by Duke Energy Indiana witnesses Messrs. Stan Pinegar and Brian Davey.

Q. PLEASE DESCRIBE THE ADDITIONAL RETAIL COST OF SERVICE STUDY YOU COMPLETED RELATED TO 12 CP.

A. In addition to the test year 4 CP retail cost of service study, a 12 CP retail cost of service study was completed per the Order in Cause No. 42873. The results of the 12 CP cost of service study are reflected in Confidential MSFR Workpaper COSS 233-244 (MTD) (revised). This 12 CP study was prepared in the same manner as the 4 CP study, with the difference between these two scenarios due to the allocation of 12 CP for production and transmission plant instead of 4 CP.

V. STEP 1 RATE ADJUSTMENT JURISDICTIONAL SEPARATION AND COST OF SERVICE STUDIES

Q. PLEASE DESCRIBE THE ADDITIONAL ANALYSIS YOU COMPLETED RELATED TO THE TWO-STEP RATE ADJUSTMENT.

A. In addition to the test year jurisdictional separation study and cost of service service studies, additional workpapers were completed in support of the Company's proposed two-step ratemaking process as it impacts the results of the jurisdictional separation study (Confidential Workpaper 2019 Step 1 (MTD) Schedule 1 through 20) and cost of service study (Confidential Workpaper 2019 Step 1 (MTD) Schedule 21 through 32 (revised). These additional workpapers were prepared in a manner that is consistent with the test year studies. The differences between these additional workpapers and the test year studies are due to the additional *proformas* provided by Ms. Douglas which were input in the regulatory ledger tool to create the additional scenario and is reflective of the Step 1 rate adjustment.

VI. DECOUPLING MECHANISM AND IMPLEMENTATION

Q. IS DUKE ENERGY INDIANA PROPOSING A RATE MECHANISM TO DECOUPLE ITS FIXED COST RECOVERY FROM ACTUAL CUSTOMER USAGES FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Yes, as introduced by Duke Energy Indiana witness Brian Davey and explained in more detail in the testimony of Duke Energy Indiana witness Dr. Daniel Hansen, the Company is proposing to recover the difference between actual fixed cost recovery for certain rate classes and the fixed costs subject to this base rate case proceeding.

Q. WHAT IS DUKE ENERGY INDIANA PROPOSING?

A. Duke Energy Indiana is proposing a new rider, the Revenue Decoupling Mechanism ("RDM") to decouple sales units from fixed cost recovery.

Q. IS THE COMPANY PROPOSING A NEW TARIFF SHEET?

A. Yes, Sheet No. 99, Revenue Decoupling Mechanism ("RDM") is the proposed tariff as reflected on Petitioner's Exhibit 7-I (MTD).

Q. CAN YOU PROVIDE MORE DETAILS ON THE MECHANICS OF HOW THE RDM WOULD WORK TO SUPPLEMENT THE EXAMPLES DR. HANSEN DESCRIBED IN HIS DIRECT TESTIMONY?

A. Each month, for each of the applicable rate classes (RS and CS), the Company would calculate the actual fixed costs recovered that month. The fixed costs recovered would be compared to the monthly portion of fixed costs allowed for recovery from this base rate case proceeding, as adjusted for the actual number of customer bills. The differences between these calculated amounts would be the decoupling amount for the RS and CS rate classes for the respective months. The monthly decoupling amounts for the applicable rate classes would be summed and deferred for subsequent inclusion in the annual RDM filing, which would recover from (or pass back to) the applicable customer classes the accumulated deferred decoupling amounts.

Specifically, to determine the allowed fixed costs recovered each month, the Company, for each applicable rate class, would determine the *number of customers billed* multiplied by the *monthly allowed fixed revenue per customer amount*.

- *The monthly number of customers billed* would be determined by taking the connection charge revenue from the billing records divided by the tariffed rate connection charge.
- *The monthly allowed fixed revenue amount* would be determined by taking the test year kWh per month as a percentage of the annual test year kWh to determine the monthly share that is then multiplied by the *annual allowed fixed revenue per customer bill amount*.
- The *annual allowed fixed revenue per customer bill amount* would be sourced from the retail cost of service study, wherein I would use the proposed revenue less energy related charges less connection charges to calculate the proposed revenues which are fixed.

The proposed fixed revenues would then be divided by the customer bill count as used by rate design in the establishment of rates to establish the annual allowed fixed revenue per customer bill amount.

Next, to determine the actual fixed costs recovered each month, the Company for each applicable rate class would use the monthly billed kWh multiplied by the *fixed revenue per kWh*.

- The *fixed revenue per kWh* is calculated by taking the previously calculated *annual fixed revenue per customer bill* amount divided by the applicable annual test year sales used by rate design in this proceeding.

The result of the monthly allowed fixed costs recovered less the actual fixed costs recovered represents the monthly RDM deferral amount. The net result of the RDM is that over a year's time, the Company would realize the fixed costs approved for recovery by the Commission, as adjusted for the actual number of customer bills.

Q. WILL THE RDM BE RECONCILED?

A. Yes, annually the RDM amounts actually recovered from customers will be reconciled with RDM amounts intended for recovery from customers, with any variance to be reflected in the subsequent year's RDM filing. This ensures a dollar-for-dollar recovery of the costs approved for recovery.

Q. DID YOU PREPARE AN EXAMPLE TO ILLUSTRATE WHAT YOU DESCRIBED PREVIOUSLY FOR DETERMINING THE RDM/DECOUPLING AMOUNT?

A. Yes, Petitioner's Exhibit 7-H (MTD), Schedules 1 through 3 demonstrate the RDM Deferral calculation for the applicable residential and commercial rate schedules for the full amount of the proposed rate increase.

Q. HOW DOES THE COMPANY INTEND TO DETERMINE THE RDM FIXED REVENUE CHARGE RELATING TO THE ACTUAL STEP 1 INCREASE?

A. The Company would determine the RDM fixed revenue charge for the actual Step 1 increase using the same methodology applicable to the full rate increase described previously, and such Step 1 fixed revenue amounts would be included in the calculation applicable to the months where Step 1 rates were in effect.

Q. PLEASE DESCRIBE THE LIKELY TIMING OF THE FIRST RDM IMPLEMENTATION.

A. The Company would first commence monthly deferral calculations upon Commission approval of the RMD, likely in July of 2020. The first filing to the Commission would cover the annual period of July 2020 through June of 2021 and be completed by the end of September 2021. The rates proposed by customer class would be the annual amount of the RDM deferral amount under or over-collected divided by projected energy sales; the projected energy sales used will be April 2022 through March 2023 to determine the respective RDM rates.

Approval by the end of March 2022 would be requested with application to customer bills assumed starting April 2022 for a year. This same schedule would be maintained for the five years the program is initially in place with a final reconciliation in year six.

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY FOR RECORDING A MONTHLY RDM DEFERRAL COMMENCING UPON COMMISSION APPROVAL IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag. Topic 980 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for accounting purposes, provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does

> not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

Q. DO YOU HAVE AN OPINION AS TO THE APPROPRIATENESS OF, AND THE ACTION REQUIRED BY, THE COMMISSION TO ALLOW FOR THE REQUESTED ACCOUNTING TREATMENT?

A. Yes. In my opinion, deferral in a regulatory asset (or liability) of the RDM that is eligible to be recovered (or returned) via a rider, until it can be included in rider rates, is appropriate from a ratemaking perspective, and such treatment will minimize the timing differences between cost recognition on the Company's books and cost recovery. In order for the Company to record an RDM deferral as a regulatory asset (or liability), it must be probable that such costs will be recovered (or returned) through rates in future periods. In order to satisfy the probability standard, the Commission's Order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Energy Indiana.

VII. <u>CONCLUSION</u>

Q. WERE PETITIONER'S CONFIDENTIAL EXHIBITS 7-A (MTD) THROUGH 7-G (MTD) (REVISED), AND EXHIBITS 7-H (MTD) THROUGH EXHIBIT 7-I (MTD) PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

PETITIONER'S REVISED EXHIBIT 7-G (MTD) IS CONFIDENTIAL

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Maria T Diaz
Maria T. Diaz

Dated: 9/9/19