FILED
September 09, 2019
INDIANA UTILITY
REGULATORY COMMISSION

REVISED PETITIONER'S EXHIBIT 4

DUKE ENERGY INDIANA 2019 BASE RATE CASE
DIRECT TESTIMONY OF DIANA L. DOUGLAS

INDEX

REVISED DIRECT TESTIMONY OF DIANA L. DOUGLAS
DIRECTOR, RATES & REGULATORY PLANNING
DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Diana L. Douglas, 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" 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 & REGULATORY PLANNING.

A. As Director, Rates & Regulatory Planning, I am responsible for the preparation of financial and accounting data used in Company rate filings.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of Indiana University, holding a Bachelor of Science Degree in Business, with a major in Accounting, with additional post-graduate course-work within the MBA program of Indiana University. Since my employment as a permanent employee in 1980 with the Company (then known as Public Service Company of Indiana, Inc.), I have held various financial and accounting positions supporting the Company and its affiliates. My position prior to Director, Rates, was that of manager responsible for fuel and joint ownership accounting. I have also had management responsibility for emission allowance accounting, general accounting for the Commercial Business Unit, and power marketing and trading settlements and back office operations. I have also held positions in Corporate Accounting, Budgets and Forecasts, and Payroll. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society.

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

A. The purpose of my testimony is to explain and support several accounting, revenue requirements and ratemaking aspects of the Company's case. My testimony will:

1) Explain the Company's planned step-in (two-step) rate adjustment process to ensure, given the Company's use of a calendar year ending December 31, 2020, forecasted test period ("Test Period"), that the rates being charged customers include costs for used and useful plant;

2) Explain the process for using the forecasted Test Period data provided by Duke Energy Indiana witness Mr. Christopher M. Jacobi to produce adjusted forecasted Test Period data for use in the jurisdictional separation and cost of service studies to produce the revenue requirements and proposed rate increase amounts for the Test Period;

3) Sponsor and support certain portions of the basic accounting exhibits ("Accounting Exhibits") required by the Minimum Standard Filing

Requirements ("MSFR") to be filed with the case-in-chief pursuant to 170 IAC 1-5-6;

4) Sponsor and support the majority of rate base *pro forma* adjustments applicable to the Test Period and certain revenue and expense *pro forma* adjustments to operating income;

5) Explain and support proposed changes to certain of the Company's existing rate adjustment riders (also referred to as tracking mechanisms or trackers) to be effective with the implementation of the Company's revised base rates;

6) Explain and support the Company's requests for certain accounting treatment and deferral authority with current or future recovery of certain expense items; and,

7) Explain and support a revision to one of my revenue workpapers and to support a supplemental revenue workpaper to enable a broader view of the impact of the proposals in this rate case that includes the rate case impacts on projected revenues associated with items that will remain in the riders post-base rate case implementation. The workpaper revision also affects numbers used in two of my other workpapers and one of my exhibits and also workpapers and exhibits of other witnesses. The new workpaper supports revised bill impact testimony, workpapers and exhibits of other witnesses, and also affects my workpaper summary exhibit.

Q. WHICH PORTION OF THE ACCOUNTING EXHIBITS REQUIRED UNDER THE MSFR WILL YOU BE SPONSORING?

A. My testimony sponsors the following portion of the Accounting Exhibits required to be filed with the case-in-chief pursuant to 170 IAC 1-5-6, which are both attached as exhibits to my testimony and also are included with Duke Energy Indiana's submission of the Minimum Standard Filing Requirements ("MSFR"):

Table 1

MSFR Reference and Exhibit Number	Exhibit
170 IAC 1-5-6 (1) (A) Petitioner's Exhibit 4-A (DLD)	Duke Energy Indiana's Comparative Balance Sheet for the historical reference period of the twelve months ending December 31, 2018 ("Historical Reference Period")
170 IAC 1-5-6 (1) (B) Petitioner's Exhibit 4-B (DLD)	Duke Energy Indiana's Cash Flow Statement for the Historical Reference Period
170 IAC 1-5-6 (1) (C) Petitioner's Exhibit 4-C (DLD)	Duke Energy Indiana's Comparative Income Statement for the Historical Reference Period
170 IAC 1-5-6 (2) Petitioner's Exhibit 4-D (DLD)	Duke Energy Indiana's Revenue Requirement Calculation for the forward-looking (*i.e.*, forecasted) test period ending December 31, 2020 ("Test Period")
170 IAC 1-5-6 (3) Petitioner's Exhibit 4-E (DLD)	Duke Energy Indiana's Jurisdictional Net Operating Income for the Test Period
170 IAC 1-5-6 (4) (A) & (B) Petitioner's Exhibit 4-F (DLD)	Duke Energy Indiana's Jurisdictional Rate Base for the Test Period
170 IAC 1-5-6 (1) (5) Petitioner's Exhibit 4-G (DLD)	Duke Energy Indiana's Capital Structure and Cost of Capital for the Historical Reference Period and for the Test Period
170 IAC 1-5-6 (1) (5) Petitioner's Exhibit 4-H (DLD)	Duke Energy Indiana's Effective Tax Rate for the Historical Reference Period and for the Test Period

The Company's remaining Accounting Exhibits are filed with the testimony of Duke Energy Indiana witnesses Mr. Christopher M. Jacobi (forecasted financial statements) and Ms. Christa L. Graft (revenue conversion factor). These will also be included with the MSFRs.

The Company will also be filing with its MSFRs the Balance Sheet, Income Statement, and Capital Structure and Cost of Capital for the Quarter Ending March 31, 2019, and will continue to update for each subsequent quarter during the pendency of this case.

Q. PLEASE EXPLAIN THE ORGANIZATION OF ANY SCHEDULES SUPPORTING THESE ACCOUNTING EXHIBITS THAT ARE BEING FILED WITH THIS CASE IN CHIEF.

A. Each of my exhibits supporting the Test Period revenue requirements (Petitioner's Exhibits 4-D (DLD) through Exhibit 4-H (DLD)) is supported by one or more supporting schedules providing differing levels of detail and *pro forma* adjustments, as applicable. The schedules are all labeled with categories, such as Rate Base, Operation and Maintenance Expenses ("O&M") or Revenues, and have been numbered with a unique schedule number within that category. This is true across the other Duke Energy Indiana witnesses who are providing revenue requirements testimony (Ms. Suzanne A. Sieferman and Ms. Graft) or *pro forma* adjustments (Ms. Sieferman, Ms. Graft and Mr. Roger. A Flick, II), although they will have their own exhibit numbering. In this way, stakeholders can identify all exhibits and *pro forma* adjustments associated with Revenues, for example, regardless of which witness sponsors them. The categories we used are:

Table 2

Category	**Schedule Numbering Prefix**
Revenue Requirements	RR
Operating Income	OPIN
Revenues	REV
O&M (Excluding, Fuel, EAs and Purchased Power)	OM
Cost of Goods Sold (Fuel, EAs and Purchased Power)	COGS
Depreciation and Amortization	DA
Taxes Other than Income Tax	OTX
Income Taxes	TX
Rate Base	RB
Capital Structure & Cost of Capital	CS

Petitioner's Exhibit 4-W (DLD) includes a list of all schedules sponsored by me with references to additional schedules within that category that are sponsored by other witnesses.

Q. WHICH RATE BASE *PRO FORMA* TEST PERIOD ADJUSTMENTS WILL YOU BE SPONSORING?

A. The rate base adjustments I am sponsoring that are attached as supporting schedules to Petitioner's Exhibit 4-F (DLD) include:

Table 3

Exhibit	***Pro Forma* Adjustments to Rate Base**
Petitioner's Exhibit 4-F (DLD)	Schedule RB2 – Pro Forma Adjustments to Plant-in-Service and Accumulated Depreciation Reserve: • Remove Asset Retirement Obligation ("ARO") Assets • Remove Non-Jurisdictional Portion of Henry County Generating Station Plant Assets • Remove Gas Pipeline Lease Asset • Remove Amount of Edwardsport Station Post-In Service Ongoing Capital Plant ("Ongoing Capital") in Excess of Settlement Caps • Remove Transmission Plant Assets Recovered via the Midcontinent Independent System Operator ("MISO") • Remove Non-Utility Customer Lighting Assets • Remove Non-Advanced Metering Infrastructure ("AMI") Secondary Meters • Adjust Accumulated Depreciation for Proposed Depreciation Rates Schedule RB4 –Adjust Regulatory Assets Included in Rate Base Schedule RB5 –Remove Non-Jurisdictional Portion of Henry County Generating Station Plant Materials and Supplies ("M&S") Inventory

The Company's remaining rate base *pro forma* adjustments will be sponsored by Ms. Sieferman.

Q. WHICH OPERATING INCOME *PRO FORMA* TEST PERIOD ADJUSTMENTS WILL YOU BE SPONSORING?

A. The operating income adjustments I am sponsoring that are attached as supporting schedules to Petitioner's Exhibit 4-E (DLD) include:

Table 4

Exhibit	*Pro Forma* Adjustments to Operating Income
Petitioner's Exhibit 4-E (DLD)	Schedule OM15 – Remove Expense for Other Post Retirement Benefits Schedule OM16 – Normalize Edwardsport Planned Outage Expenses Schedule DA3 – Adjust and Annualize Depreciation Expense for Production Plant Schedule DA4 – Adjust and Annualize Depreciation Expense for Transmission Plant Schedule DA5 – Adjust and Annualize Depreciation Expense for Distribution Plant Schedule DA6 – Adjust and Annualize Depreciation Expense for General Plant Schedule DA7 – Adjust and Annualize Depreciation Expense for Intangible Plant Schedule DA8 – Adjust General Plant Depreciation for MISO RECB/MVP Credits Schedule DA10 – Adjust and Annualize Regulatory Asset Amortization Schedule OTX5 – Adjust and Annualize Property Tax Expense

In addition, I will be supporting the adjusted Test Period income tax expense calculation and *pro forma* adjustments that are attached as supporting schedules to Petitioner's Exhibit 4-H (DLD). This includes:

- the federal and state current and deferred income tax impacts of other *pro forma* adjustments;
- the Company's synchronized interest deduction;
- the Company's parent interest deduction ("Muncie Remand deduction"); and,
- the removal of certain Investment Tax Credit ("ITC") and Excess Deferred Income Taxes ("EDIT") amortization credits which will not be included in the cost of service for base rates, but rather be included in the Company's Standard Contract Rider 67 – Tax and Merger Credits Adjustment ("Rider 67" or "Credits Rider").

These income tax supporting schedules are as follows:

Table 5

Exhibit	***Pro Forma* Income Tax Calculation**
Petitioner's Exhibit 4-H (DLD)	Schedule TX1 – Summary of Income Tax Expense Schedule TX2 – Computation of Current Federal and State Income Taxes Schedule TX3 – Computation of Synchronized Interest Deduction Schedule TX4 –Computation of Parent Interest Deduction Schedule TX5 – Remove IGCC State ITC Credit Schedule TX6 – Computation of Deferred Federal and State Income Taxes Schedule TX7 – ITC Credit Amortization

The Company's remaining operating income *pro forma* adjustments will be sponsored by Ms. Sieferman, Ms. Graft, and Mr. Flick.

Q. WHICH EXISTING RATE ADJUSTMENT RIDERS WILL YOU ADDRESS IN YOUR TESTIMONY?

A. The rate adjustment riders that I will cover include the Company's:

- <u>Standard Contract Rider 61</u> - Integrated Coal Gasification Combined Cycle ("IGCC") Generating Facility Revenue Adjustment ("Rider 61" or "IGCC Rider"), which is being proposed to be discontinued;

- Standard Contract Rider 65 – Transmission and Distribution Infrastructure Improvement Cost ("TDSIC") Rate Adjustment ("Rider 65" or "TDSIC Rider");
- Standard Contract Rider 66-A – Energy Efficiency ("EE") Revenue Adjustment ("Rider 66-A" or "EE Rider"); and
- Standard Contract Rider 67 - ("Credits Rider").

Copies of the red-lined and clean revised tariff sheets for the TDSIC, EE and Credits Riders will be attached to my testimony as Petitioner's Exhibit 4-M (DLD) through 4-T (DLD). In addition, I will be sponsoring Petitioner's Exhibit 4-U (DLD) and 4-V (DLD), a red-lined and clean updated Appendix A to the Company's Tariff, listing all ongoing Rate Adjustments Riders post-rate case. They will also be included with the complete set of base rate and other rider tariffs that will be filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF).

Ms. Sieferman and Ms. Graft will address the Company's other existing rate adjustment riders

Q. WHAT REQUESTS FOR AUTHORITY FOR ACCOUNTING TREATMENT, DEFERRAL AUTHORITY, AND RATE RECOVERY WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I will support the Company's requests for revised accounting and rate recovery treatment or new deferral authority with current or future recovery of certain expense or capital items as follows:

- Continued recovery of the remaining net book value of Wabash River Unit 6, which was retired on December 7, 2016;
- Deferral of certain costs incurred or to be incurred for coal ash remediation and closure, with financing (*i.e.*, carrying) costs until included in future rates, with current recovery of certain incremental costs incurred through December 31, 2018, with financing costs and additional costs forecasted to be incurred in 2019 and 2020 for two sites;
- Creation of a major planned outage cost normalization reserve account to be used to defer the Edwardsport major planned outage costs included in the 2020 Test Period for recovery over 7 years; and
- Continued deferral of pension settlement accounting costs with amortization for future recovery.

Q. ARE YOU SPONSORING OTHER EXHIBITS?

A. Yes. Petitioner's Exhibits 4-I (DLD) through 4-L (DLD) support the calculation of the estimated Step 1 rate adjustment that I will discuss conceptually in Section II. and discuss in more detail in Section VII. These exhibits also have supporting schedules that reference the same categories and numbering scheme as I discussed earlier. They include:

Table 6

Exhibit Number	**Exhibit**
Petitioner's Exhibit 4-I (DLD)	Duke Energy Indiana's Step 1 Rate Adjustment and Revenue Requirement Calculation using year-end December 31, 2019 rate base ("Step 1")
Petitioner's Exhibit 4-J (DLD)	Duke Energy Indiana's Estimated Step 1 Jurisdictional Net Operating Income for the Test Period
Petitioner's Exhibit 4-K (DLD)	Duke Energy Indiana's Estimated Step 1 Jurisdictional Rate Base for the Test Period
Petitioner's Exhibit 4-L (DLD)	Duke Energy Indiana's Estimated Capital Structure and Cost of Capital for Step 1

Q. ARE YOU SPONSORING ANY WORKPAPERS TO SUPPORT YOUR EXHIBITS AND TESTIMONY?

A. I will be sponsoring workpapers supporting Petitioner's Exhibits 4-D (DLD) through Petitioner's Exhibit 4-H (DLD) which will be included with other MSFRs in the MSFR Volumes filed as part of the Case-in-Chief. I will refer to these workpapers in my Testimony as "MSFR Workpapers". In addition, I will be sponsoring workpapers supporting Petitioner's Exhibit 4-L (DLD) which will be filed separately, along with two additional workpapers. See Petitioner's Exhibit 4-W for a list of sponsored workpapers and the exhibits they relate to and the MSFR reference where they are being filed, if applicable. One of the additional workpapers I am sponsoring is Supplemental Workpaper REV5-DLD, which shows the forecasted post-rate case rate adjustment rider revenues associated with costs and credits remaining in riders. This supplemental view includes the impact of proposals made in this proceeding, including the removal of Utility Receipts Tax from the rider revenues, the use of the revised allocation factors used to develop base rates, and the inclusion of a new amortization amount in Rider 67 for deferred protected EDIT that will begin when new base rates are implemented, as I discuss later in my testimony in Section VIII-D.

Q. PLEASE EXPLAIN THE REVISION YOU REFERENCED MAKING TO A REVENUE WORKPAPER.

A. MSFR Workpaper REV3-DLD, filed with Section 1-5-8(a)(2) of the Company's MSFR filing, presents, by rider, 2020 projected revenue amounts by rate schedule and rate code for items currently recovered in riders, with subtotals for amounts that will remain in riders after the rate case and amounts that are being included in the rate case. The amount of rider revenues associated with the rider costs being included in rate case is used, along with base rate revenues at current rates, to obtain the total present revenue amount used in the cost of service study. The revenues shown for five of the current riders (Rider 62, Rider 72, Rider 73, Rider 61 and Rider 71) were correct in total and at the rate schedule level, but had originally been improperly allocated to the individual rate codes within the HLF rate schedule on the basis of projected 2020 kwh sales instead of kw demand, which is used in those riders to bill HLF rate schedule customers. All other allocations to other rate schedules and rate codes were unaffected by the change.

The revised values on this Revised MSFR Workpaper REV3-DLD were also summarized and used in two of my other workpapers, which have also been revised to reflect the new values. These include: MSFR Workpaper REV1-DLD, which shows forecasted and adjusted revenues with *pro forma* adjustments by account, and MSFR Workpaper REV2-DLD, which shows total present revenues and total present rider revenue remaining in the riders for costs that were not included in base rates. These workpapers were also filed with Section 1-5-8(a)(2) of the Company's MSFR filing.

The revised values also were further summarized and used in Petitioner's Exhibit 4-E (DLD), Schedule REV1, which presents a summary of forecasted and adjusted revenue from electric sales with *pro forma* adjustments. This exhibit has also been revised to reflect the workpaper changes. The changes also affected Petitioner's Exhibit 6-A (CLG), Schedule REV2, sponsored by Ms. Graft, who is also revising that exhibit.

None of these changes affected the total revenue deficiency or total proposed revenue requirement in this proceeding. However, because the cost of service study uses present revenues by rate code, the HLF allocation change also affected several exhibits and workpapers of Company Witnesses, Ms. Maria T. Diaz, Mr. Jeffrey R. Bailey, and Mr. Flick.

Q. PLEASE EXPLAIN HOW SUPPLEMENTAL WORKPAPER REV5-DLD DIFFERS FROM THE RIDER REVENUE INFORMATION PROVIDED ON REVISED MSFR WORKPAPER REV-3-DLD YOU JUST DISCUSSED.

A. Revised MSFR Workpaper REV3-DLD, shows projected rider revenues for costs and credits that will remain in riders after the rate case using current allocation methods, as approved in the last base rate case in Cause No. 42359, and including a provision for Utility Receipts Tax ("Tax") recovery. It does not include any new costs or credits that would result from a rate case order or other changes proposed in this case.

Supplemental workpaper REV5-DLD presents projected rider revenues for the same costs and credits that will remain in riders after the rate case, but also reflects changes proposed in this rate case. This includes incorporating the allocation factors used for the proposed base rates, such as the change from using 12CP demand to 4CP demand to allocate production and transmission plant, as supported by Ms. Diaz, or that would result from approval of the proposed rates (such as using new Transmission and Distribution revenue requirements to develop allocation factors for the TDSIC Rider.) It also includes removal of the provision for URT from the revenues, as supported by Ms. Graft. Finally, it also includes amortization of the protected EDIT that has been deferred in 2018 and 2019 using the amortization period proposed in this case, as discussed in Section VII-D of my testimony. These last two items result in a change of approximately $1.5 million less in projected rider revenues after the rate case. Company Witnesses Ms. Diaz, Mr. Brian P. Davey, and Mr. Bailey have used this supplemental workpaper in several of their revised testimony, workpapers or exhibits.

II. TWO-STEP RATE ADJUSTMENT PROCESS

Q. WHAT IS THE PURPOSE OF THE COMPANY'S PROPOSED TWO-STEP RATE ADJUSTMENT PROCESS?

A. Because Duke Energy Indiana's proposed base rates in this proceeding are calculated based on forecasted rate base at the end of the Test Period (December 31, 2020), the Company proposes to implement the requested rate increase in two steps to reasonably reflect the utility property that is used and useful at the time rates are placed in effect. The Company proposes a two-step adjustment in rates that will utilize the Company's existing Rider 67 (*i.e.*, the Credits Rider).[1] Step 1 will adjust rates when new base rates are implemented, expected to occur in mid-2020, the middle of the Test Period. Step 2 will adjust rates after the end of the Test Period. The proposed two-step process and the use of an existing rate adjustment rider (Credits Rider) will ensure that the rates established in this proceeding are timely adjusted and reflect used and useful utility property at the time rates are adjusted. The following illustrates the Company's proposal:

[1] Section VIII-D. in the Rate Adjustment Riders section of my testimony discusses this and other proposed changes to the Credits Rider.

Table 7

Components of Rates	Step 1 – Mid-2020	Step 2 – 1st Qtr 2021
Base Rates	Company's Proposed Base Rates Using Test Period Forecast with Forecasted Rate Base as of 12/31/20	Company's Proposed Base Rates Using Test Period Forecast with Forecasted Rate Base **(No Change from Step 1 Base Rates)**
+	+	+
Rate Adjustment Credit in Rider 67	Credit for Difference in Revenue Requirements Using Actual Net Utility Plant and Property In-Service at 12/31/19	Credit for Difference in Revenue Requirements Using Actual Net Utility Plant and Property In-Service at 12/31/20 (If Less Than Forecasted 12/31/20 Plant – Otherwise Zero)
=	=	=
Net Rates Reflecting Actual Used and Useful Net Utility Plant and Property	Net Rates Reflecting Actual Used and Useful Net Utility Plant and Property as of 12/31/19	Net Rates Reflecting Actual Used and Useful Net Utility Plant and Property as of 12/31/20

Q. PLEASE DESCRIBE IN MORE DETAIL WHAT WILL HAPPEN IN STEP 1 WHEN BASE RATES ARE IMPLEMENTED IN MID-2020.

A. Upon receipt of the Commission's order in this proceeding, expected in mid-2020, the Company proposes to file and implement the base rates supported by Duke Energy Indiana witnesses Mr. Jeffrey R. Bailey and Mr. Flick, if approved, or as adjusted if required by the Commission's order. These rates will be left in place until new rates are approved in the Company's next retail rate proceeding.

These base rates will be based on the forecasted test period 2020, including forecasted plant and property which may not have been completed or be in-service to customers at the time of the Step 1 increase. As such, the rates will likely require an adjustment using the Credits Rider (Rider 67) to be sure that only rate base that is in-service at the end of 2019 will be included in the Step 1 rates.

Q. HOW WILL THE COMPANY ENSURE CUSTOMERS DO NOT PAY FOR PLANT THAT HASN'T BEEN DEMONSTRATED TO BE USED AND USEFUL AT THE TIME THE BASE RATES ARE IMPLEMENTED MID-2020?

A. The Company will implement an adjustment using the Credits Rider to reflect revised revenue requirements using 2019 actual value of net plant and property, so long as the 2019 actual value of net plant and property does not exceed the forecasted 2020 values that were included in the Commission approved rates. These adjusted revenue requirements will also adjust the depreciation expense and include the 2019 actual capital structure and cost of capital values in the calculation. In this way, the combination of the base rates plus the Credits Rider Step 1 rate adjustment will reasonably reflect actual used and useful plant-in-service as of the Step 1 timing of implementation of the base rates, while aligning the depreciation calculation with the plant-in-service amount included in rate base and keeping the capital structure aligned with the same timing as the rate base.

Q. PLEASE DESCRIBE WHAT WILL HAPPEN IN STEP 2 AFTER ACTUAL DECEMBER 31, 2020 RATE BASE VALUES ARE KNOWN.

A. The same calculation and comparison will be done as for calculation of the Step 1 Credits Rider rate adjustment, except the Company will compare the actual

December 31, 2020 net plant and property amounts to the forecasted December 31, 2020 values included in the Commission approved base rates. So long as the total revenue requirement amounts using actual December 31, 2020 net plant and property, depreciation and capital structure and cost of capital amounts don't exceed the forecasted 2020 values that were included in the Commission approved rates, the Step 1 Credits Rider rate adjustment will be modified to reflect the revenue requirements using the actual December 31, 2020 plant and property values. But if the revenue requirements using the actual December 31, 2020 plant and property values are higher than the revenue requirements the Commission approved in base rates, no ongoing credit adjustment to base rates will be required, and the Step 1 Rate Adjustment component of the Credits Rider will be adjusted to zero following a compliance filing.

Under either scenario, the Credits Rider will be adjusted from the amount included in Step 1 rates via a compliance filing as soon as practicable after year-end results become available, expected to be sometime during the first quarter of 2021.

In this way, the combination of the base rates plus the Credits Rider Step 2 rate adjustment will reasonably reflect actual used and useful plant-in-service as of the December 31, 2020 Test Period end date, while aligning the depreciation calculation with the plant-in-service amount included in rate base and keeping the capital structure aligned with the same timing as the rate base, until new base rates are approved in the Company's next retail base rate case.

Q. HOW WILL THE STEP 1 AND STEP 2 REVENUE REQUIREMENT ADJUSTMENTS BE INCORPORATED INTO CUSTOMER RATES?

A. The Two-Step revenue requirement adjustment amounts by rate group will be included as a component in the Credits Rider. The revised rates for the Credits Rider (also reflecting other changes needed due to the Commission's base rate order) will be implemented contemporaneously with the implementation of base rates in Step 1 on a service-rendered basis and as soon as practicable in Step 2.[2] See additional information about the Credits Rider in Section VIII. D. of my testimony.

Q. IS THE COMPANY'S TWO-STEP RATE ADJUSTMENT PROPOSAL REASONABLE?

A. Yes. This approach combines the use of an existing tracking mechanism with the mid-test period implementation of forecasted rates to ensure that the Company's rates for service reflect used and useful property in both Steps 1 and 2 and reasonably represents Duke Energy Indiana's cost to serve customers during the Test Year.

III. <u>REVENUE REQUIREMENTS PROCESS</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROCESS FOR DEVELOPING REVENUE REQUIREMENTS.

[2] Service-rendered basis is based on when energy is delivered/used, rather than when bills are rendered to customers.

A. Our Rates and Regulatory Planning team obtained the Test Period forecast from witness Mr. Jacobi and his Midwest financial forecasting team. We reviewed the forecast to identify rate base and operating income items that required a lower level of detail for ratemaking purposes than what was in the forecast. In most cases sufficient detail was available. In other cases, we could use MSFR responses to identify information needed for ratemaking *pro forma* adjustment purposes and jurisdictional separation study and cost of service allocation purposes. In still other cases, it was necessary to use calendar year 2018 or year-end December 31, 2018 to allocate certain costs to the lower level of detail required for ratemaking. The primary forecast adjustments with which I was involved or for which I had oversight included: allocation of plant, property and equipment to plant FERC accounts from plant functions; allocation of various combined regulatory assets and amortization to individual regulatory assets; and allocation of rider revenues to be included in base rates to rate classes, using the current allocation methods and factors applicable to each rider.[3] These forecast

[3] Riders other than Riders 60 and 63 currently use allocation factors from Cause No. 42359 and approved for use in the individual rider proceedings. Riders 60 and 63 use forecasted kwh to develop a single factor for all rate schedules; Riders 61, 62, 71, and 73 use 12 CP demand, with further allocations to individual rate codes using forecasted kwh, except for the HLF group which uses forecasted non-coincident peak ("NCP") demand; Riders 68 and 70 use 12 CP demand, with further allocations to individual rate codes using forecasted kwh; Rider 65 uses retail transmission and distribution revenue allocations, with the LLF and HLF rate codes allocated on a delivery voltage basis, and other rate schedules further allocated to individual rate codes using forecasted kwh; Rider 66 direct assigns costs to the Residential and Non-Residential rate groups, with further allocations to individual rate codes using forecasted kwh; Rider 67 allocates using retail rate base for tax credits and O&M for merger credits, with further allocations to rate codes using forecasted kwh; and Rider 72 allocates using production and transmission plant, with further allocations to rate codes using forecasted kwh, except for the HLF group which uses forecasted NCP demand.

adjustments are summarized and included on Petitioner's Exhibits 4-E (DLD) and 4-F (DLD).

Pro Forma adjustments to the Test Year were also necessary, primarily in support of ratemaking adjustments to reflect impacts to the forecast of ratemaking requests that would become effective upon Commission Approval. For example, we needed to remove the portion of rider revenues and expenses in the forecast that we planned to leave in riders rather than include in the cost of service for base rates. Other examples include adjusting rate base and depreciation for the impact of new depreciation rates, amortizing regulatory assets using new proposed amortization periods or reflecting new deferrals and amortizations, and removing items from the forecast that can't be recovered from retail jurisdictional customers, such as brand advertising expense and the Edwardsport post-in-service ongoing capital ("Ongoing Capital") amounts in excess of the regulatory caps for April 2015 through December 2017. These *pro forma* adjustments were done at a Total Company level to get to the Adjusted Test Period amounts.

Certain additional adjustments to the *pro forma* adjustments were made by Duke Energy Indiana witness Ms. Maria T. Diaz and her team to further functionalize and classify costs at a lower level of detail in preparation for the jurisdictional separation study. She will discuss these functionalization adjustments and provide workpapers supporting them. Ms. Diaz prepared the jurisdictional separation study and provided the retail jurisdictional portion of the adjusted Test Period rate base, present revenues and operating income amounts to enable the calculation of revenue deficiency at present rates and proposed revenue requirements. The proposed incremental revenues were then used by Ms. Diaz to perform the cost of service study used to design rates.

IV. BASIC ACCOUNTING EXHIBITS FOR TEST PERIOD

A. Financial Statements and Accounting Practices

Q. PLEASE EXPLAIN PETITIONER'S EXHIBITS 4-A (DLD), 4-B (DLD), AND 4-C (DLD).

A. Petitioner's Exhibit 4-A (DLD) is Duke Energy Indiana's Comparative Balance Sheet for the Historical Reference Period, which along with Mr. Jacobi's Petitioner's Exhibit 3-C (CMJ) (the Comparative Balance Sheet for the Test Period) is intended to comply with 170 IAC 1-5-6 (1). Petitioner's Exhibit 4-B (DLD) is Duke Energy Indiana's Cash Flow Statement for the Historical Reference Period, which along with Mr. Jacobi's Petitioner's Exhibit 3-D (CMJ) (the Cash Flow Statement for the Test Period) is intended to comply with 170 IAC 1-5-6 (2). Petitioner's Exhibit 4-C (DLD) is Duke Energy Indiana's Comparative Income Statement for the Historical Reference Period, which along with Mr. Jacobi's Petitioner's Exhibit 3-B (CMJ) (the Comparative Income Statement for the Test Period) is intended to comply with 170 IAC 1-5-6 (3).

Q. WERE PETITIONER'S EXHIBITS 4-A (DLD), 4-B (DLD), AND 4-C (DLD) PREPARED UNDER YOUR SUPERVISION?

A. No, I am not involved in the preparation of these financial statements on a monthly nor annual basis. They are prepared by the Company's Accounting function under the direction of Duke Energy Corporation's Controller. The corporate Accounting function maintains the accounting books and records and prepares financial statements and reports for internal use and external distribution for Duke Energy Indiana, as well as other affiliates.

Duke Energy Indiana's accounting and financial reporting policies and practices are in conformance with Generally Accepted Accounting Principles (GAAP). As a public Company whose securities are traded in interstate commerce, Duke Energy Corporation and its subsidiaries are subject to the purview of the Securities and Exchange Commission ("SEC"), and its financial statements filed with the SEC must be accompanied by the opinion of an independent auditor that the statements have been prepared in accordance with GAAP.

In addition, the Company maintains its books and records in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USofA"), which has been adopted by the Indiana Utility Regulatory Commission ("Commission") as the accounting standard for Indiana utilities in its administrative rules at 170 IAC 4-2-1.1. While there are some differences between GAAP and the USofA, they are generally consistent with one another. The GAAP financial statements differ from the FERC USofA primarily in the classification of accumulated deferred income taxes, regulatory assets and liabilities, cost of removal obligations, maturities of long-term debt and equity treatment of post-in-service carrying costs.

Q. HOW ARE AUDITS OF THE COMPANY'S ACCOUNTING BOOKS AND RECORDS AND FINANCIAL STATEMENTS PERFORMED AND BY WHOM?

A. Formal audits of the accounting books and records of Duke Energy Corporation and its affiliates, including Duke Energy Indiana, are performed annually by Deloitte & Touche, LLP ("Deloitte'). In addition, the internal audit department of Duke Energy Corporation supplements the audits performed by Deloitte with internal audits.

Q. WHAT OTHER CONTROLS DOES THE COMPANY UTILIZE TO ENSURE THE ACCURACY OF ITS ACCOUNTING BOOKS AND RECORDS AND FINANCIAL STATEMENTS?

A. Duke Energy Corporation complies with the directives of the Sarbanes Oxley regulations, as well as various internally-established control procedures. Examples of the Company's internal control procedures include authority limits and approvals required for expenditures and general ledger transactions, accounting system access limitations, and bank and general ledger account reconciliations. The books and records are also subject to audit by FERC and the applicable utility regulatory agencies in each jurisdiction.

B. Revenue Requirements and Operating Income Exhibits

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-D (DLD).

A. Petitioner's Exhibit 4-D (DLD) Schedule RR1 is Duke Energy Indiana's Revenue Requirement Calculation for the Test Period. The calculation multiplies the jurisdictional rate base at original cost from the Company's jurisdictional separation study (as also shown on Petitioner's Exhibit 4-F (DLD)) by the Company's weighted average cost of capital from Petitioner's Exhibit 4-G (DLD), to obtain the required electric operating income. The jurisdictional electric operating income at present rates from the Company's jurisdictional separation study (as also shown on Petitioner's Exhibit 4-E (DLD)) is then subtracted to get the operating income deficiency of $293,758. This is multiplied by the gross revenue conversion factor for equity (as sponsored by Ms. Graft and shown on the bottom of Petitioner's Exhibit 4-G (DLD) Schedule CS3) to get the electric operating revenue deficiency. This $394,570 revenue deficiency is the amount of additional electric operating revenue needed to be produced by proposed rates.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD).

A. Petitioner's Exhibit 4-E (DLD) is a series of schedules supporting Duke Energy Indiana's Jurisdictional Net Operating Income for the Test Period. Schedule OPIN1 provides a summary at both present rates and proposed rates. Column B shows the Company Adjustments (including the calculation of the adjustments) needed to adjust the proposed additional electric operating revenue to achieve the $293,758 net utility operating income deficiency from Petitioner's Exhibit 4-D (DLD). Schedule OPIN2 provides a summary of the adjustments made to the corporate forecast operating income items, which I discussed in Section III. Schedule OPIN3 is a summary of operating income *pro forma* adjustments by line item and by *pro forma*, with sponsoring witness and *pro forma* schedule numbers. The operating income *pro forma* adjustments I am sponsoring are also supporting schedules to this exhibit.

C. Rate Base Exhibits and Discussion of Special Items

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-F (DLD).

A. Petitioner's Exhibit 4-F (DLD) is a series of Schedules supporting the rate base included in the cost of service in this proceeding and is intended to comply with 170 IAC 1-5-6 (4). Schedule RB1 is a summary of the Test Period amounts and the amounts as adjusted for ratemaking purposes. Schedules RB2 through RB5 provide additional detail on the adjustments.

Q. HAS DUKE ENERGY INDIANA INCLUDED IN-SERVICE EDWARDSPORT PLANT, PROPERTY AND EQUIPMENT IN RATE BASE?

A. Yes. The Edwardsport plant went into service on June 7, 2013. The Company has included approximately $2.651 billion of Total Company original cost investment amount for the major project investment for the IGCC facility at Edwardsport, less the forecasted accumulated depreciation reserve as of December 31, 2020. The Commission's December 27, 2012 Order in Cause No. 43114 IGCC-4S1 ("IGCC-4S1") established the estimated $2.595 billion Hard Cost Cap amount at June 30, 2012 and the parameters for determining the Additional AFUDC that could be added to the actual amount as of June 30, 2012 until the facility was in-service. The final Hard Cost Cap amount of $2.651

billion was approved in the Commission's August 24, 2016 Order in Consolidated Cause No. 43114 IGCC-15 ("IGCC-15"). (The first filing that included the final Hard Cost Cap Plus Additional AFUDC amount was IGCC-12, which was consolidated with the IGCC-15 case, along with several other filed proceedings.)

In addition, Duke Energy Indiana adjusted the forecasted Test Period ending balance of Ongoing Capital investment at Edwardsport, less the forecasted accumulated depreciation reserve as of December 31, 2020, via a *pro forma* adjustment to remove the net book value of the Ongoing Capital investment from April 2015 through December 2017 that exceeded the Ongoing Capital cap amounts approved in the Commission's IGCC-15 order. I will discuss this *pro forma* adjustment in Section V., the Rate Base *Pro Forma* Adjustments section of my testimony, along with other rate base adjustments.

Q. DOES THIS CASE INCLUDE ANY OTHER RATE BASE ITEMS FOR EDWARDSPORT?

A. Yes. As with all other Company generating units, the Test Period end forecasted amounts of Fuel and Materials and Supplies ("M&S") Inventories have been included in Rate Base. These items were not proposed to be included in the IGCC Rider when the rider design was approved by the Commission in Cause No. 43114 on November 20, 2007 (the original IGCC Certificate of Public

Convenience and Necessity ("CPCN") and Clean Coal Technology Certificate proceeding), so have not been part of the IGCC Rider proceedings.

Q. PLEASE EXPLAIN WHAT HAS BEEN INCLUDED IN RATE BASE RELATIVE TO GALLAGHER GENERATING STATION NET UTILITY PLANT.

A. The Company has included the forecasted balance of the net book value of the utility plant for the two remaining Gallagher Generating Station ("Gallagher") coal generating units (Units 2 and 4), which the Company is committed to either retire or cease burning coal by December 31, 2022, pursuant to the settlement agreement approved by Commission's IGCC-15 order, which specified that ratemaking for the retirement of Gallagher Station Units 2 and 4 will be consistent with normal retirement accounting. As with all other Company generating units, the Test Period end forecasted amounts of Fuel and Materials and Supplies ("M&S") Inventories have been included in Rate Base.

Q. WHAT IS NORMAL RETIREMENT ACCOUNTING?

A. Under GAAP, retirements of equipment that are considered "normal" retirements are accounted for by crediting plant accounts and debiting accumulated depreciation for the original cost of the equipment. In other words, the values of both the investment and its related accumulated depreciation are reduced by the original cost of the equipment that has been retired. If costs are required to dismantle, decommission or otherwise remove the plant and equipment upon retirement ("Cost of Removal"), these costs are debited to accumulated depreciation. It is standard practice for Indiana electric utilities to include an estimate for the Cost of Removal in depreciation studies, so that by the time the asset is retired, both the cost of the asset and estimated cost of removal have been recovered from customers who have benefitted from the service of that asset.

Q. WHAT HAPPENS IF A GENERATING UNIT IS RETIRED EARLIER THAN ASSUMED IN ITS LAST DEPRECIATION STUDY OR IS REQUIRED TO INCLUDE COSTS, SUCH AS COAL ASH POND CLOSURES OR REMEDIATION, THAT MAY NOT HAVE BEEN FULLY INCLUDED IN DEPRECIATION RATES?

A. Depending on the specific circumstances, including the materiality of the remaining net book value or unrecovered costs and how early the generating unit may be retired, the retirement may not be considered normal under GAAP, and the retirement of the plant or the cost of removal may not be able to be charged to accumulated depreciation. In this case, the net book value remaining in the plant asset accounts or the additional cost of removal may need to be charged directly as a one-time expense, unless the Company receives authority from the Commission to defer and recover the remaining costs or it is probable the costs can be recovered from customers due to a history of such costs being recoverable either due to statute or standard regulatory practice, such as through depreciation rates or the granting of deferral authority and recovery in similar situations.

Q. HAVE ANY OF THESE NON-NORMAL RETIREMENTS OCCURRED AT GALLAGHER STATION?

A. Yes. Gallagher coal generating Units 1 and 3 retired on January 31, 2012 pursuant to a New Source Review litigation settlement agreement with the Environmental Protection Agency[4]. Under the settlement, Duke Energy Indiana had the option of converting Gallagher Units 1 and 3 to natural gas fuel or retiring the units. In Cause No. 43956, the Company proposed to retire the units and replace their capacity with the acquisition of a portion of the existing Vermillion CT Peaking Station ("Vermillion"). The Commission found this proposal to be prudent. As part of the Commission's December 28, 2011, Order in Cause No. 43956 approving the Company's request, the deferral of the remaining net book value of the Gallagher Units 1 and 3 assets was booked as a regulatory asset, with amortization and recovery over 14 years. The Commission's Order noted on page 63:

> "In regard to the remaining net book value of Gallagher Units 1 and 3, there is no question that these units have been used and useful in providing service to Duke Indiana's customers for approximately 50 years."

The Company was also authorized to account for dismantling costs through normal removal accounting.

In addition, the Company was authorized to defer for subsequent recovery the retail jurisdictional portion of the costs associated with the gas conversion "Plan B" preservation option (converting Gallagher Units 1 and 3 to natural gas fuel) through year-end 2011. Accordingly, the Company has included both the

[4] https://www.epa.gov/sites/production/files/documents/dukeenergy-cd.pdf

remaining net book value of the Gallagher coal generating Units 1 and 3 and the gas conversion preservation costs in rate base in this proceeding as a regulatory asset, proposed to be amortized over the remainder of the original 14-year remaining life period approved in Cause No. 43956. The Company asks for the continuation of this regulatory treatment in this case for the remaining net book value of Gallagher Units 1 and 3.

Q. WHAT HAS BEEN INCLUDED IN RATE BASE RELATED TO THE BAGHOUSES CONSTRUCTED AT GALLAGHER STATION APPROVED IN CAUSE NOS. 42622/42718?

A. The Commission's May 24, 2006, Order in Cause Nos. 42622/42718 approved a settlement agreement ("Phase 1 Settlement Agreement") and CPCN for the construction of the Company's Phase 1 Environmental Compliance Plan, which included certain clean coal technology projects, including the addition of baghouses to all four units at Gallagher ("Gallagher Baghouses"). The Phase 1 Settlement Agreement limited the retail recovery of the Gallagher Baghouses to no more than $102 million in total project expenditures for the four baghouse projects. It also limited its CWIP ratemaking recovery via the Company's ECR Rider 62 of capital costs applicable to the Gallagher Baghouses to no more than $98 million for all four units. In addition, the Company was authorized to defer for recovery in its next general retail rate case all reasonably incurred capital costs for these projects in excess of $98 million up to $102 million. The in-service date for the baghouses on Units 1 and 2 was December 2007, and the in-service date for the baghouses on Units 3 and 4 was April 2008. As has been explained and supported previously in ECR Rider 62 and Rider 71 testimony since the baghouses were placed in service, the Company ultimately spent more than $102 million in total, or $105,218,000.

The original cost of the amount in excess of $102 million was recorded by the Company as a non-utility asset and has not been included in rate base in this proceeding. Accordingly, the Company has included in rate base (in the remaining net utility plant for Units 2 and 4 and the remaining net book value of Units 1 and 3 in the regulatory asset just discussed) each unit's portion of the retail jurisdictional amount of $98 million in cost that was approved to be included for CWIP ratemaking in the ECR Rider and is now being moved to base rates and a regulatory asset for the retail jurisdictional portion of the $4 million of additional costs in excess of $98 million up to the $102 million cost recovery cap.

Q. HAS DUKE ENERGY INDIANA INCLUDED ITS PORTION OF THE ACQUIRED VERMILLION PLANT, PROPERTY AND EQUIPMENT IN RATE BASE?

A. Yes. The Company was issued a CPCN for its acquisition of 400 MW or 62.5% of Vermillion in the Commission's order in Cause No. 43956. The Vermillion acquisition closed on February 1, 2012. The Company has included both net utility plant and M&S inventory for the station in rate base in this case.

Q. HAS DUKE ENERGY INDIANA INCLUDED THE COST OF ITS IN-SERVICE AMI METERS AND THE AMI PROJECT IN RATE BASE?

A. Yes. As discussed by Duke Energy Indiana witness Mr. Donald L. Schneider, Jr., the project is expected to be complete by the end of 2019. In addition, on June 29, 2016, the Commission's order in Cause No. 44720 (the Company's TDSIC plan case) ("TDSIC Order") approved a settlement agreement ("TDSIC Settlement Agreement") that, among other terms, authorized the deferral of 100% of the post-in-service depreciation associated with the AMI project up to $60 million for recovery in a subsequent retail base rate proceeding, with amortization over a 10-year period without carrying costs. It also approved the deferral of post-in-service carrying costs associated with the AMI project at a 4.72% cost rate up to $15 million for recovery in a subsequent retail base rate proceeding, with amortization over a 10-year period with no carrying costs in the subsequent retail rate case.

Q. DID THE COMPANY EXCEED THE RECOVERY CAPS AND HAS THE COMPANY INCLUDED THE AMI DEFERRED DEPRECIATION AND POST-IN-SERVICE CARRYING COSTS IN RATE BASE?

A. No, the Company did not exceed the recovery caps, and, although it has included amortization expense for the amortization over 10 years of approximately $18.4 million of deferred depreciation and $13.1 million of post-in-service carrying costs for the AMI project, it has not included these regulatory assets in rate base, and the post-in-service carrying costs and depreciation deferrals will end upon the Step 1 implementation of base rates in this proceeding.

Q. IN ADDITION TO EDWARDSPORT PLANT AND THE GALLAGHER BAGHOUSES, HAS THE COMPANY INCLUDED OTHER PLANT THAT IS CURRENTLY RECEIVING CWIP RATEMAKING TREATMENT IN THE COMPANY'S RATE ADJUSTMENT RIDERS IN RATE BASE?

A. Yes. All plant forecasted to be in service by December 31, 2020, with CWIP ratemaking treatment in the Company's rate adjustment riders has been included in rate base. This includes plant approved under Ind. Code Ch. 8-1-39-9 ("TDSIC Statute"), Indiana Code § 8-1-8.4 ("Federal Mandate Statute), or designated as Qualified Pollution Control Plant ("QPCP"), Ind. Code Ch. 8-1-8.7 (clean coal technology), clean energy, Ind. Code. Ch 8-1-8.8 or renewables projects, Ind. Code. Ch 8-1-8.8. In addition to my discussion in Section VIII., Ms. Sieferman and Ms. Graft will discuss the rate base items and operating income items that are currently included in riders that will be included in base rates.

Q. WHAT IS THE NATURE OF THE REGULATORY ASSETS INCLUDED IN RATE BASE?

A. Petitioner's Exhibit 4-F (DLD) Schedule RB2 details the balances of the regulatory assets included in rate base. The regulatory assets consist of:

Table 9

Deferred Depreciation on Renewable, Environmental and Other Production Plant	$22,951,000
Post-in-Service AFUDC or Carrying Costs on Renewable, Environmental and Other Production Plant	60,508,000
20% Deferrals on TDSIC Costs under the TDSIC Statute	45,071,000
20% or 40% Deferrals on CCR Phase 1 and Other Federally Mandated Costs under the Federal Mandates Statute	39,288,000
Net Book Value of Other Production Plants Retired Early	41,473,000
Gallagher Baghouse Additional Costs	3,060,000
SO2 Emission Allowance Costs	9,520,000
Coal Ash Remediation and Financing Costs	211,716,000
Total Regulatory Assets at 12/31/2020 Included in Rate Base	$433,587,000

Costs for these regulatory assets have been deferred or forecasted pursuant to the terms of the applicable statute, Commission Order or governing settlement agreement approved by Commission Order, except in the case of the new deferral requests, which will be further discussed in testimony in this proceeding.

These regulatory assets may also be categorized by status of regulatory approval as follows:

Table 10

Remaining Unamortized Balances of Amounts Previously Included in Cause No. 42359	$22,855,000
Additional Costs Deferred After Rate Base Cutoff for Items Included in Cause No. 42359	37,038,000
Costs Deferred Under New Deferral Approvals Received After Cause No. 42359	89,609,000
Costs Deferred Under New Deferral Approvals Received After Cause No. 42359 and Currently Recovered in the ECR Rider	21,376,000
Recovered as Plant-in-Service in Cause No. 42359 with Regulatory Asset Deferral Approval Received After Cause No. 42359 and Asking Continued Recovery in this Case	25,450,000
Recovered as Plant-in-Service in Cause No. 42359 and Asking Continued Recovery in this Case	16,023,000
Requesting Approval in this Case	221,236,000
Total Regulatory Assets at 12/31/2020 Included in Rate Base	$433,587,000

Q. HAS DUKE ENERGY INDIANA INCLUDED A PREPAID PENSION ASSET IN RATE BASE?

A. Yes, it has. Duke Energy Indiana has included the forecasted Test Period End Prepaid Pension Asset amount, approximately $151 million (Total Company), in rate base. The Prepaid Pension Asset is the cumulative amount of cash contributions to the pension trust fund in excess of the cumulative amount of accrued pension cost. The Prepaid Pension Asset presented in the case is calculated consistent with GAAP under Accounting Standards Codification (ASC) 715, (formerly Financial Accounting Standard No. 87 or "FAS 87".) The Test Year End balance is based on the actual balances as of December 31, 2018 and the change associated with accrued pension cost for 2019 and 2020. Duke

Energy Indiana's management has made use of available cash to fund the pension plan with investor capital in excess of required funding amounts and reduce the liquidity risk of future payments.

Q. HOW DO THE ADDITIONAL PENSION CONTRIBUTIONS BENEFIT CUSTOMERS?

A. The additional pension contributions to the trust fund result in additional trust fund investment income that directly reduces annual ASC 715 pension expense. The Test Year pension expense included in the cost of service for customers is therefore lower than it otherwise would have been without these additional pension contributions represented in the prepaid pension asset.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE INCLUSION OF A UTILITY'S PREPAID PENSION ASSET IN RATE BASE?

A. Yes. In Cause No. 44075, Indiana Michigan Power Company sought to include a prepaid pension asset in rate base. The Commission approved this request. This specific finding was appealed, and on March 11, 2014, the Indiana Court of Appeals upheld the Commission's decision on the matter.

D. Other Exhibits

Q. PLEASE EXPLAIN PETITIONER'S EXHIBITS 4-G (DLD) AND 4-H (DLD).

A. Petitioner's Exhibit 4-G (DLD) Schedules CS1 and CS2 present Duke Energy Indiana's Capital Structure and Cost of Capital for the Historical Reference Period and Schedules CS3 and CS4 present Duke Energy Indiana's Capital

Structure and Cost of Capital for the Test Period. Both are in the same format, calculated using the same expanded regulatory presentation and the same methodology as has been used in recent years for all the Company's rate adjustment riders that include return on investment as part of the calculation, and the same basic workpapers are being filed in this case as parties have seen in the various rider filings. The forecasted financial capital structure, provided by Mr. Jacobi and supported by Duke Energy Indiana witness Mr. John L. Sullivan III, has been expanded to include traditional Indiana regulatory components including accumulated deferred income taxes, unamortized investment tax credits, and customer deposits. The components of the Company's regulatory capital structure include cost rates computed in accordance with traditional Indiana regulatory practice (the embedded cost of long term debt, average financial rates for ITC and zero cost of capital for deferred income taxes). As discussed in the testimony of Mr. Flick, the Company is proposing the Commission approve the Company's request to allow it to use a 2% interest rate on customer deposits eligible for interest accrual for the Test Period, rather than the 6% currently effective rate. Use of this lower rate on the customer supplied funds in the capital structure will benefit all customers by lowering the rate of return, resulting in lower revenue requirements of approximately $1 million. The rate of return on equity is the existing approved 10.5% for the Historical Reference Period and the proposed 10.4%, supported by the testimony of Mr. Robert B. Hevert. The testimony of Mr. Sullivan provides background and support for the Company's financing practices and policies and targeted capital structure ratios.

Q. HAVE YOU ADJUSTED THE FINANCIAL CAPITAL STRUCTURE FOR ITEMS OTHER THAN THOSE PREVIOUSLY DESCRIBED?

A. Yes, I have. As has been standard practice in the calculation of the Company's regulatory capital structure for many years, the Company has removed a long-term financing issuance specifically related to the liability assumed by the Company to pay the Rural Utility Service ("RUS") resulting from the settlement of litigation with Wabash Valley Power Alliance ("WVPA") as well as removing the Gas Pipeline Lease Liability recorded as a capital lease for payments under a Gas Services Agreement with Southern Indiana Gas and Electric Company, Inc., d/b/a Vectren Energy Delivery of Indiana, Inc. to provide gas to the Edwardsport IGCC plant via a gas pipeline which Vectren constructed and owns ("Gas Pipeline Lease"). This was removed for ratemaking due to the treatment of the payments under the lease for both ratemaking and income tax purposes as a "pay-as-you-go" operating lease rather than a capital lease. See additional discussion about this agreement in Section V. explaining the adjustment made to remove the corresponding Gas Pipeline Lease Asset from Rate Base.

In addition, adjustments have been made to eliminate certain deferred income taxes that are recorded on the Company's books in accordance with the provisions of Statement of Financial Accounting Standards No. 109, for financial statement reporting purposes, but which have historically been excluded in the capital structure for ratemaking purposes, as well as to remove the deferred income taxes related to the Gas Pipeline Lease. The Company has made certain other adjustments to the accumulated deferred income tax balances to remove deferred taxes associated with impairments taken by the Company for accounting books purposes but which are not used for tax purposes. As approved by the Commission in its IGCC-4S1 Order, the Company has excluded deferred income taxes associated with the amount of the IGCC capital investment in excess of the agreed-upon Hard Cost Cap, including Additional AFUDC, from the capitalization structure for purposes of calculating the rate of return. Similarly, the Company has removed the deferred taxes associated with the non-AMI legacy meter (*i.e.*, legacy meters being replaced with AMI meters) ("Legacy Meters") impairments taken by the Company, so that customers will neither be harmed by nor benefit from the inclusion of related deferred taxes in the capital structure for the portions of the IGCC plant and non-AMI Legacy Meters that shareholders are paying for, not customers. The Company has also included an adjustment to remove the deferred income tax asset balances related to the Company's deferred utilization of Investment Tax Credits. The Company has also adjusted the amount of deferred income taxes included in the Capital Structure by including the unamortized balance of the regulatory liability for the EDIT amounts resulting from the 2017 Tax Cuts and Jobs Act ("TCJA"), and from other previous state and federal tax changes in the deferred income tax amount as an additional zero cost source of capital component in the calculation. MSFR Workpaper TX7-DLD details these deferred income tax adjustments.

Finally, short-term debt has been excluded from the capital structure consistent with previous Commission Orders, including the Company's last two base rate cases in Cause Nos. 40003 and 42359 and the practice used for capital structure calculation for CWIP ratemaking for QPCP property (and used by the Company in all its capital rate adjustment riders for the plant currently receiving CWIP ratemaking treatment, but now being included in base rates). However, the Company has included an $150,000,000 inter-company notes payable for Commercial Paper issued by Duke Energy Corporation on behalf of the Company that is part of the Company's permanent long-term financing. The Company has been reflecting this low-cost debt (forecasted at 2.512% for the Test Period) as part of long-term debt in its capital structure and cost of capital for all capital rider filings beginning with Cause No. 42061 ECR-12 which included long-term debt as of June 30, 2008.

Q. WHAT RATE OF RETURN IS THE COMPANY PROPOSING?

A. As shown on Petitioner's Exhibit 4-G (DLD) Schedule CS3, the Company is proposing a rate of return (weighted average cost of capital) of 6.15%. The recent rate of return for the Historical Reference Period, as shown on Schedule CS1, is 6.20%.

Q. WHAT IS THE COST RATE ASSIGNED TO LONG-TERM DEBT?

A. As shown on Petitioner's Exhibit 4-G (DLD) Schedule CS4, the weighted average cost rate applicable to the Company's long-term debt for the Test Period is 4.88%. As shown on Schedule CS2, the weighted average cost rate applicable to the

Company's long-term debt for the Historical Reference Period is 4.94%.

Q. PLEASE EXPLAIN THE CALCULATION OF THE COST RATE ASSIGNED TO LONG-TERM DEBT.

A. The cost rate assigned to long-term debt has been developed by dividing the summation of the annual interest requirements and amortization of costs related to the issuance of long-term debt, including costs of interest rate hedges, by the net proceeds received from the issuance of the debt. The net proceeds are defined to include unamortized debt premium, discount, issuance expense and unamortized gain or loss on reacquired debt. For ratemaking purposes, it is appropriate to use net proceeds (*i.e.*, the net investible proceeds from the debt) as the denominator in this equation to give recognition to the fact that the cost rate will be applied to rate base, ensuring that all debt-related costs associated with rate base are covered in the Revenue Requirements calculation.

V. RATE BASE *PRO FORMA* TEST PERIOD ADJUSTMENTS

Q. PLEASE EXPLAIN ADJUSTMENT PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB1.

A. Petitioner's Exhibit 4-F (DLD) Schedule RB1 summarizes the *pro forma* adjustments made to rate base. Ms. Sieferman sponsors Petitioner's Exhibit 5-D (SES) Schedule RB3, the adjustment to remove costs currently included in SO2 emission allowance inventory and transfer to a regulatory asset to be included in base rates for proposed recovery. I will sponsor and discuss Petitioner's Exhibit

4-F (DLD) Schedules RB2, RB4 and RB5, which adjust the value of other rate base items.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB2 TO ADJUST NET UTILITY PLANT.

A. Petitioner's Exhibit 4-F (DLD) Schedule RB2 details eight *pro forma* adjustments needed to adjust net utility plant to the Test Period ending net utility plant amount projected to be used and useful plant at December 31, 2020. The first seven adjustments remove various items included in forecasted net plant that need to be excluded from rate base for the proper development of new base rates. These include adjustments to remove:

- ARO Plant Assets
- the Non-Jurisdictional Portion of Henry County Generating Station
- Gas Pipeline Lease Asset
- Edwardsport Station Ongoing Capital in Excess of Settlement Caps
- the Portion of (RECB/MVP) Transmission Plant Assets Recovered via MISO
- Non-Utility Customer Lighting Plant
- Non-AMI Legacy Meters

Q. PLEASE EXPLAIN WHY ARO PLANT ASSETS WERE REMOVED FROM NET UTILITY PLANT FOR RATEMAKING.

A. GAAP, under Accounting Standards Codification (ASC) 410 covering Asset Retirement and Environmental Obligations ("ARO Accounting"), requires companies to recognize ARO liabilities on their books and records for asset retirements for long-lived assets when certain situations occur that legally commit the company to incurring costs to retire the asset. At the same time, it requires the establishment of a new offsetting ARO plant asset on their books and records, which gets depreciated over time until it is time to retire and remove the underlying asset. Although a new plant asset is established on the Company's books, it is not an asset that has required the expenditure of cash, so is not appropriate for including in the development of rates. Accordingly, the amounts included in the adjusted forecast for the Company's ARO assets were removed from production and general plant-in-service and associated accumulated reserve for depreciation, reducing net utility plant by $435,944,000 as of the end of the Test Period.

Q. PLEASE EXPLAIN WHY A PORTION OF HENRY COUNTY GENERATING STATION WAS REMOVED FROM NET UTILITY PLANT FOR RATEMAKING.

A. The Company purchased Henry County Generating Station in February 2003, following the December 19, 2002, approval of the terms of the purchase and related ratemaking pursuant to a settlement agreement in Cause No. 42145. The terms of the settlement agreement and the Commission's order require that for retail ratemaking purposes the Company separate out and exclude the costs and revenues associated with 50 MWs of capacity of Henry County that had previously been committed to a wholesale sale with Wabash Valley Power

Association, Inc., ("WVPA") in Cause No. 41569. This ratemaking treatment was used in the Company's last retail base rate case. Accordingly, the 50 MW WVPA portion of the original cost production (including the acquisition adjustment), transmission and general plant-in-service, and associated accumulated reserve for depreciation were removed, reducing net utility plant by $19,640,000 as of the end of the Test Period. MSFR Workpaper RB24-DLD details the calculation of the adjustment and shows the calculation of the 36.56% used in the calculation.

Q. PLEASE EXPLAIN WHY THE GAS PIPELINE LEASE ASSET WAS REMOVED FROM NET UTILITY PLANT FOR RATEMAKING.

A. As approved by the Commission in its Order in Cause No. 43601, on October 2, 2008, the Company entered into a Gas Service Contract with Southern Indiana Gas and Electric Company, Inc., d/b/a Vectren Energy Delivery of Indiana, Inc. to provide gas to the Edwardsport IGCC plant via a gas pipeline which Vectren constructed and owns. The pipeline was completed in the spring of 2010, with May 2010 being the first month for which a payment under the 37-year contract was required. Until the IGCC plant was in-service, the contract payments were capitalized to the IGCC Project in accordance with FERC accounting guidance, subject to the IGCC Hard Cost Cap.

Once the plant went in-service in June 2013, although the Company is required to treat the contract as a capital lease for GAAP and SEC reporting purposes, the Company has been treating payments under the contract for regulatory accounting and ratemaking purposes as a gas transportation charge, similar to other charges the Company incurs for gas service to its Cayuga CT and Wheatland facilities, which are charged to fuel using FERC account 547. Likewise, the Company has included such costs pursuant to the Gas Service Contract in its cost of fuel for determination of fuel adjustment charges under its Standard Contract Rider No. 60 – Fuel Cost Adjustment beginning with Cause No. 38707 FAC-95. I discussed this planned regulatory accounting and ratemaking treatment in my Direct Testimony in Cause No. 43114 IGCC-6, and Ms. Sieferman discussed the inclusion of these costs in her Direct Testimony in Cause No. 38707 FAC-95. No parties took exception to the treatment in either proceeding and Commission orders were received December 27, 2012, and March 27, 2013, respectively.

Like my discussion of the required GAAP accounting for AROs, both a liability and an asset are set up on the accounting books and records under capital lease accounting. The Company has excluded the lease liability from long-term debt for the Capital Structure calculations in all capital rider proceedings since it was established on the Company's books with no parties taking exception and in the Capital Structure in this proceeding. Because the Company is using the operating lease treatment for ratemaking purposes for expense, it is necessary to remove both the lease liability and the lease capital asset from ratemaking. Accordingly, the Company has removed $7,458,000 from net utility production plant in-service as of the end of the Test Period.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE EDWARDSPORT ONGOING CAPITAL AMOUNTS FROM NET UTILITY PLANT FOR RATEMAKING.

A. The Commission's IGCC-15 Order established caps on the retail amount of post-in-service Ongoing Capital investment from April 1, 2015 through December 31, 2017 that could be recovered through retail rates, with any amounts over the caps needing to be excluded for ratemaking purposes from both the IGCC Rider and base rates. Per Petitioner's Exhibit 2-B (DLD), Page 7 of 10 filed with my Direct Testimony in Cause No. 43114 IGCC-17 ("IGCC-17"), the Company exceeded the April 2015 to December 2016 cap by $9,022,138 and the calendar year 2017 cap by $2,792,771, for a total of $11,814,909 on a retail original cost plant basis. On a total company net depreciated plant basis, the net utility plant-in-service value as of 12/31/2020 for production plant was reduced by $11,393,000 due to this Ongoing Capital cap.

Q. PLEASE EXPLAIN WHY THE PORTION OF THE COMPANY'S TRANSMISSION PROJECTS RECOVERED VIA MISO WERE REMOVED FROM NET UTILITY PLANT FOR RATEMAKING.

A. The Company has received approval from MISO for certain Company-owned capital projects under MISO's Regional Expansion and Criteria and Benefits ("RECB") process and under MISO's Transmission Expansion Plan ("MTEP") as RECB projects or Multi-Value Projects ("MVP"). MISO is currently (or, for approved projects not yet completed, will be upon completion) reimbursing the

Company for the cost of these projects by charging MISO transmission owners for the cost of the expansion projects through Schedule 26 and charging all market participants for the expansion projects through 26A charges.[5] At the same time, the Company is paying its allocated MISO share of the costs for these same projects through the Schedule 26 and 26A charges it is billed. Customers then pay for the Company's share of the projects through the Company's Rider 68 (currently referred to as the MISO Rider) rates which include these costs. Accordingly, the Company has removed $28,388,000 from net utility transmission plant in-service as of the end of the Test Period.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NON-UTILITY CUSTOMER LIGHTING FROM NET UTILITY PLANT FOR RATEMAKING.

A. The Company removed $30,695,000 of customer lighting plant from net utility distribution plant in-service as of the end of the Test Period to ensure this plant was not included in the cost of service to all customers because the Company is being reimbursed for the cost of the lighting equipment by specific customers under the terms of customer-specific Outdoor Lighting Equipment Service ("OLES") agreements.

Q. PLEASE EXPLAIN WHY NON-AMI LEGACY METERS WERE REMOVED FROM NET UTILITY PLANT FOR RATEMAKING.

[5] Two of the approved RECB projects approved as Generator Interconnection Projects are reimbursed at 50% of cost. All others are 100% reimbursable.

A. On June 29, 2016, the Commission approved a settlement agreement in Cause No. 44720 (the Company's TDSIC plan case) ("TDSIC Settlement Agreement") that, among other terms, agreed that the Company would not request recovery of or on the undepreciated value of current meters being replaced by AMI meters as part of the Company's AMI project. Accordingly, the Company has removed $14,596,000 from net utility distribution plant in-service as of the end of the Test Period for the remaining net book value of the non-AMI Legacy Meters.

Q. PLEASE EXPLAIN THE REMAINING ADJUSTMENT TO NET UTILITY PLANT SHOWN ON PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB2.

A. After considering these seven *pro forma* adjustments to net utility plant, the Company then factored in the difference in the accumulated depreciation balance as of December 31, 2020 that would result from application of the new depreciation rates proposed in this case (assumed to be effective July 1, 2020) from the current rates that were used in the forecast. This resulted in an additional reduction in net utility plant in the amount of $68,041,000, for a total reduction in net utility plant for all *pro forma* adjustments of $616,155,000. MSFR Workpapers RB7-DLD through RB21-DLD and RB24-DLD are being filed to support all these adjustments. I will discuss more about the impact of the proposed change in depreciation rates on depreciation expense in Section VI. of my testimony.

Q. PLEASE EXPLAIN THE ADJUSTMENT ON PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB4 TO ADJUST REGULATORY ASSETS.

A. Petitioner's Exhibit 4-F (DLD) Schedule RB4 details the balances of the regulatory assets included in the Company's rate base in this request and the *pro forma* adjustment amounts for each. Like the adjustment needed to net utility plant to reflect the impact on accumulated depreciation of the difference between the proposed and current depreciation rates, it was necessary to adjust the December 31, 2020 balance of the regulatory assets for the impact on the balance of the difference between the proposed amortization assumed to be effective July 1, 2020, and current amortization. In addition, adjustments were necessary to include two regulatory assets not included in the forecast that we are requesting approval of regulatory asset rate base treatment in this proceeding (financing costs on coal ash costs incurred and the SO_2 EA costs moved from inventory to a regulatory asset). These *pro forma* adjustments resulted in an increase in regulatory assets to be included in rate base in the amount of $8,472,000. MSFR Workpapers RB2-DLD, RB3-DLD, RB23-DLD and RB24-DLD are being filed to support these adjustments. I will discuss more about the impact of the proposed changes in amortization periods on regulatory asset amortization expense in Section VI. of my testimony.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB5 TO ADJUST MATERIALS AND SUPPLIES ("M&S") INVENTORY.

A. Consistent with the adjustment made to reduce net utility plant for the 50 MW WVPA portion of the Henry County Generating Station pursuant to the Commission's order in Cause No. 42145, the Company has excluded 36.56% of the M&S Inventory for the station. Petitioner's Exhibit 4-F (DLD) Schedule RB5 reflects the resulting reduction in M&S Inventory of $210,000. MSFR Workpaper RB4-DLD and MSFR Workpaper OM1-SES support this adjustment.

VI. OPERATING INCOME *PRO FORMA* TEST PERIOD ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OM15 – REMOVE EXPENSE FOR OTHER POST RETIREMENT BENEFITS ("OPEB").

A. Petitioner's Exhibit 4-E (DLD) Schedule OM15 removes $7,089,000 from Test Period employee fringe benefits expense charged to FERC account 926 to reduce the level of OPEB expense included to zero. Please see MSFR Workpaper OM1-DLD for support for the adjustment amount. This adjustment was made because the level of external funding that the Company has made pursuant to Commission Orders in Cause Nos. 40388 and 42359 in the Grantor Trust established to fund the payment of future OPEB liabilities ("Grantor Trust"), plus the earnings on the Grantor Trust funds, has been deemed by the Company's management to be sufficient to pay benefits in the foreseeable future without additional customer funding for this expense item.

The balance of the Grantor Trust as of December 31, 2018 was $109,180,715, and the retail portion is 91.23% of that balance ($99,605,566).

Under the terms of the Commission's Order in Cause No. 40388 approving the Company's OPEB Settlement Agreement with the Office of Utility Consumer Counselor ("OUCC") under which the Grantor Trust was established to fund OPEB, the amounts held by the Grantor Trust are restricted to the payment of OPEB liabilities and any taxes or expenses incurred by the Grantor Trust. Once all OPEB liabilities, taxes and expenses have been paid (not expected to occur until sometime after 2040), any remaining retail jurisdictional assets shall be credited to retail customers unless the Settling parties agree to alternative treatment. The OPEB Settlement Agreement expired December 31, 2015, except for the provision that retail customers be credited with any remaining retail assets at the end of its life, unless the Settling parties agree to alternative treatment.

Because the amount in the Grantor Trust has been deemed currently sufficient to pay benefit amounts to retirees and OPEB expense charged to FERC account 926 has been removed from the Cost of Service in this case, the Company does not intend to make additional contributions to the Grantor Trust, but will reevaluate the sufficiency of the Grantor Trust funding in the Company's next retail base rate case. See the Direct Testimony of Duke Energy Indiana witness Ms. Renee H. Metzler for additional background on the Grantor Trust and the Company's OPEB benefits. Please see Workpaper OM1-DLD for a copy of the 12/31/2018 investment statement for the Grantor Trust.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OM16 – NORMALIZE EDWARDSPORT PLANNED OUTAGE EXPENSES.

A. Petitioner's Exhibit 4-E (DLD) Schedule OM16 removes $46,401,000 from Test Period production maintenance costs for the incremental cost of the first major planned outage planned for the spring of 2020 at Edwardsport Station. As discussed in the testimony of Duke Energy Indiana witness Mr. Cecil T. Gurganus, this is the first time for a planned outage that includes the steam turbine, in addition to major maintenance on gasifiers and combustion turbines. He explains that a major planned outage of this type is expected to occur approximately every seven years. Because this additional maintenance cost is not representative of an ongoing level of maintenance expense at the station, we have removed this cost from the Test Period and are proposing deferral and establishment of a major planned outage reserve account, with amortization over seven years. I will discuss this proposal in more detail in Section IX. C. of my testimony. Please see MSFR Workpaper OM2-DLD for the estimated costs of projects included in this major planned outage.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE DA1.

A. Petitioner's Exhibit 4-E Schedule DA1 summarizes the *pro forma* adjustments made to depreciation expense. Ms. Graft sponsors Petitioner's Exhibit 6-D (CLG) Schedule DA2, the adjustment to remove depreciation deferrals related to riders. I will sponsor and discuss Petitioner's Exhibit 4-E Schedules DA3 through DA8 which adjust and annualize depreciation expense based on the Company's proposed depreciation and amortization rates and forecasted adjusted depreciable plant balances as of December 31, 2020, the determination of which I explained when discussing Petitioner's Exhibit 4-F (DLD) Schedule RB2 in Section V. of my testimony, and a *pro forma* reduction due to credits received from MISO. The total increase in Test Period depreciation expense due to the Petitioner's Exhibit 4-E Schedule DA3-DA8 adjustments I am sponsoring is $145,294,000.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULES DA3 THROUGH DA7 – ADJUST AND ANNUALIZE DEPRECIATION EXPENSE FOR DEPRECIATION EXPENSE FOR PRODUCTION, TRANSMISSION, DISTRIBUTION AND GENERAL PLANT.

A. Petitioner's Exhibit 4-E Schedule DA3 details the *pro forma* adjustment to adjust and annualize depreciation expense for Production Plant based on the Company's proposed depreciation rates and forecasted adjusted depreciable plant balances as of December 31, 2020. The schedule shows the total projected depreciation included in the forecast at current rates, as-adjusted projected December 31, 2020 plant in-service, current depreciation rates, annualized depreciation calculated using current rates and as-adjusted plant balances, proposed depreciation rates, annualized depreciation calculated using proposed rates and as-adjusted plant balances, and the total pro forma adjustment. Petitioner's Exhibit 4-E Schedule

DA4 does the same for Transmission Plant, as do DA5 for Distribution Plant, DA6 for General Plant, and DA7 for Intangible Plant.

The development of the proposed depreciation rates for Production, Transmission, Distribution and General Plant is discussed in the Direct Testimony of Duke Energy Indiana witness Mr. John J. Spanos. However, the Company proposes to continue to use the currently approved 15-year life 6.67% depreciation rates for AMI meters which were approved in the TDSIC Order, and the meter rate calculated by Mr. Spanos for all other legacy digital meters. The decommissioning and dismantlement costs included in the depreciation study are discussed in the Direct Testimony of Duke Energy Indiana witness Mr. Jeffrey T. Kopp. The forecasted retirement dates for production plant that were used in the depreciation study are discussed in the Direct Testimony of Duke Energy Indiana witness Mr. Keith B. Pike. The depreciation rates for the Electric Plant Acquisition Adjustment and Intangible Plant were provided by our internal Asset Accounting department and are unchanged from current rates.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE DA8.

A. Petitioner's Exhibit 4-E (DLD) Schedule DA8 details the *pro forma* adjustment made to General Plant depreciation expense related to credits the Company receives from MISO associated with RECB and MVP assets. This reduced General Plant depreciation expense by $42,000.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE DA9.

A. Petitioner's Exhibit 4-E (DLD) Schedule DA9 summarizes the *pro forma* adjustments made to Regulatory Asset amortization expense. Ms. Graft sponsors Petitioner's Exhibit 6-D (CLG) Schedule DA11, the removal of regulatory asset amortizations that will remain in riders rather than being embedded in base rates. I will next sponsor and discuss Petitioner's Exhibit 4-E (DLD) Schedule DA10.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE DA10 - ADJUST AND ANNUALIZE REGULATORY ASSET AMORTIZATION EXPENSE.

A. Petitioner's Exhibit 4-E (DLD) Schedule DA10 increases Test Period regulatory asset amortization expense by $43,963,000, due primarily to the inclusion of amortization of new regulatory assets deferred since the last base rate case pursuant to various Commission Orders. MSFR Workpaper DA2-DLD provides detail for the calculation, showing the proposed amortization periods for each regulatory asset and the basis for the amortization period, which are generally based on the remaining lives of the assets for production-related regulatory assets included in rate base, such as deferred depreciation and post-in-service carrying costs, or were previously set in various Commission orders or Settlement Agreements. Smaller dollar rate base and expense items without a set amortization period in a previous order were generally proposed for amortization over three years. This includes the $2,413,000 of forecasted rate case expenses proposed to be amortized over three years in this case. MSFR Workpaper DA1-DLD provides the support for the December 31, 2020 balance, and MSFR Workpapers DA3-DLD and DA4-DLD provide additional detail for the regulatory assets not included in rate base, including the rate case expenses.

Q. HOW DOES THE COMPANY PLAN TO HANDLE AMORTIZATIONS INCLUDED IN BASE RATES THAT BECOME FULLY AMORTIZED BEFORE THE NEXT BASE RATE CASE?

A. The Company plans to include credits in its Credits Rider when the amortizations included in base rates end.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OTX5– ADJUST AND ANNUALIZE PROPERTY TAX EXPENSE.

A. Petitioner's Exhibit 4-E (DLD) Schedule OTX5 adjusts and annualizes property tax expense using property tax rates based on 2018 net book value and property tax expense applied to the forecasted net book value of plant-in-service as of December 31, 2020. This adjustment increases property tax expense by $637,000. The inputs for the calculation were provided by and the calculation and amounts were reviewed by the Company's Tax Department and Duke Energy Indiana witness Mr. John R. Panizza.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX1– ADJUST AND ANNUALIZE FEDERAL AND STATE INCOME TAX EXPENSE.

A. Petitioner's Exhibit 4-H (DLD) Schedule TX1 summarizes the amounts of the forecast adjustments to remove non-utility current income taxes and the total *pro forma* adjustments made to Total Company Test Period federal and state income tax expense. In addition, it shows the retail jurisdictional amounts at present rates, the taxes associated with the increase in pre-tax operating income due to the proposed revenue requirements increase, and the final Test Period income tax amounts at proposed rates. From the current and deferred federal and state income tax and investment tax credit amount included in the 2020 forecast provided by Mr. Jacobi, $230,000 of non-utility tax was removed to get to the adjusted 2020 forecast. We then removed $12,718,000 in pro forma adjustments. The resulting Total Company Test Period amount was used by Ms. Diaz as the starting point for the jurisdictional separation study, and she provided the retail jurisdictional present rate amounts. Then the income tax amount associated with the proposed increase in revenue requirements was calculated for inclusion in the cost of service study by Ms. Diaz. The adjustment to income taxes for the proposed increase in revenue requirements is an increase of $99,206,000 in retail jurisdictional income tax expense. Petitioner's Exhibit 4-H (DLD) Schedules TX2-TX7, which I will discuss, support these amounts. MSFR Workpapers TX1 (DLD) – TX9 (DLD) will also be filed further supporting the calculations.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX2.

A. Petitioner's Exhibit 4-H (DLD) Schedule TX2 shows the computation of current federal and state income tax expense at the Total Company level, as well as at the retail jurisdictional level for present and proposed rates. Column D shows the pro forma adjustments for each of the pre-tax book income items used in the current income tax calculation (which were detailed and supported by either Ms. Sieferman, Ms. Graft, Mr. Flick or me) and pro forma adjustments coming from Petitioner's Exhibit 4-H (DLD) Schedules TX3 – TX5, which I will explain.

Q. WAS THIS CALCULATION OF CURRENT FEDERAL AND STATE INCOME TAX EXPENSE PERFORMED USING THE RATES AND BASIC INCOME TAX COMPUTATION PROCESS EXPLAINED BY MR. PANIZZA?

A. Yes. As can be seen on line 31 of Petitioner's Exhibit 4-H (DLD) Schedule TX2, we used the 21% statutory rate in computing federal current income tax expense and, as can be seen on line 40, we used the 5.375% average annual statutory rate for Indiana for 2020 for computation of current state income tax expense.

Q. DOES PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX2 REFLECT THE SYNCHRONIZED INTEREST EXPENSE CONCEPT PREVIOUSLY APPROVED BY THIS COMMISSION IN RETAIL ELECTRIC RATE PROCEEDINGS?

A. Yes. The application of this concept results in a determination of the interest expense deduction for the calculation of current income taxes for ratemaking purposes by applying the interest synchronization factor to *pro forma* original cost depreciated rate base. As the name implies, this results in a calculation of annualized interest expense which is synchronized with the rate base used for regulatory purposes, rather than the total company interest expense that may also include interest expense supporting non-utility items and which is not annualized. Petitioner's Exhibit 4-H (DLD) Schedule TX3 shows the computation of this interest amount which was used to calculate the pro forma adjustment amount included on line 25, in column D of Petitioner's Exhibit 4-H (DLD) Schedule TX2.

Q. DOES PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX2 REFLECT A DEDUCTION FOR THE "PARENT INTEREST" CONCEPT PREVIOUSLY APPROVED BY THIS COMMISSION IN RETAIL ELECTRIC RATE PROCEEDINGS?

A. Yes. The application of this Muncie Remand concept results in an additional interest expense deduction, for ratemaking purposes only, in calculating current federal and state income taxes due to the Company's participation in a Duke Energy Corporation Consolidated tax return. This adjustment reduces Test Period income taxes by allocating a portion of Duke Energy Indiana's parent company's interest deduction to Duke Energy Indiana for purposes of computing income tax expense, thereby providing a tax benefit to customers. The Total Company interest allocated under this procedure, as shown on Petitioner's Exhibit 4-H (DLD) Schedule TX4 and line 26 of Column D on Petitioner's Exhibit 4-H (DLD) Schedule TX2, is $13,095,000, and the federal and state income tax expense benefit to retail jurisdictional customers from this additional deduction is approximately $3,305,996.

Petitioner's Exhibit 4-H Schedule TX4 shows the calculation of the parent interest amount using: 1) the December 31, 2020 forecasted balance of Duke Energy Indiana's total equity capital; times 2) Duke Energy Corporation's consolidated long-term debt to equity ratio for debt applicable to support of utility operations (exclusive of merger-related debt); times 3) the average cost of the parent's debt applicable to support of utility operations. The support for the parent debt amounts and calculations was provided by Mr. Sullivan.

Q. PLEASE EXPLAIN THE ADJUSTMENT ON PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX5 THAT IS REFLECTED ON LINE 44, COLUMN D OF PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX2.

A. This *pro forma* adjustment removes the full amount ($2,109,000) of state investment tax credit reflected in the 2020 forecast for state income tax (State Adjusted Gross Income Tax or "AGIT"). The Company has qualified for a Coal Gasification Technology Investment Tax Credit of $15,000,000 per year over 10 years related to its construction of the IGCC generating facility at Edwardsport and continued operation using Indiana coal and satisfying other requirements related to the operation of the power plant. The credit can be used to reduce the Company's tax liability for AGIT or the Utility Receipts Tax ("URT"). In the 2020 forecast, the credit was applied to both types of tax. The credit is being removed in full from the Test Period cost of service as the Company plans to include this IGCC tax incentive benefit, which is currently a credit to customer rates in the IGCC Rider that is being discontinued, as a credit to customer rates in its Rider 67 ("Credits Rider"). This provides transparency to stakeholders and provides a practical way to adjust rates when the 10-year period ends at the end of 2022. I will discuss this in more detail in Section VIII. D. below.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX6.

A. Petitioner's Exhibit 4-H (DLD) Schedule TX6 shows the computation of deferred federal and state income tax expense at the Total Company level, as well as at the retail jurisdictional level for present and proposed rates. Column B shows the *pro forma* deferred income tax adjustments for each of the temporary accounting books/tax timing differences giving rise to deferred income taxes that were impacted by the other *pro forma* adjustments to pre-tax book income, which arose from the *pro forma* adjustments to utility plant in service, depreciation, regulatory assets and amortization of regulatory assets and discussed in Sections V. and VI. of my testimony. In addition, the amortization of Excess Deferred Income Tax ("EDIT") on line 15 of Schedule TX6 was removed because, like the state ITC credit, this credit will be passed to customers in the Credits Rider instead of being included in the cost of service for base rates to provide transparency to stakeholders.

Q. WHAT INCOME TAX RATES WERE USED TO CALCULATE DEFERRED INCOME TAXES?

A. We used the 21% statutory rate in computing federal deferred income tax expense and 4.900% (the final statutory income tax rate under current Indiana law that will take effect July 1, 2021, after the currently scheduled annual tax rate reductions end.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-H (DLD) SCHEDULE TX7.

A. Petitioner's Exhibit 4-H (DLD) Schedule TX7 details the amounts for amortization of Investment Tax Credits (ITC.) No *pro forma* adjustment was necessary for these items, so it is included for informational purposes only.

VII. <u>ESTIMATED STEP 1 RATE ADJUSTMENTS</u>

Q. HAS THE COMPANY ESTIMATED THE AMOUNT OF THE STEP 1 REVENUE REQUIREMENT AND RATE ADJUSTMENTS?

A. Yes.

Q. PLEASE EXPLAIN THE PROCESS USED TO DEVELOP THE ESTIMATED STEP 1 REVENUE REQUIREMENT AND RATE ADJUSTMENTS.

A. The Company started with the Adjusted Total Company Operating Income and Rate Base as presented in Petitioner's Exhibits 4-E (DLD) and 4-F (DLD) and discussed in Sections IV., V. and VI. of my testimony. We then replaced the adjusted December 31, 2020 forecast values for all rate base components with the adjusted December 31, 2019 forecast values, including utility plant-in-service and accumulated depreciation. Depreciation expense for 2020 was then recalculated using the proposed depreciation rates discussed previously, and current income taxes were adjusted.

The resulting revised Total Company Operating Income and Rate Base were provided to Ms. Diaz to perform the jurisdictional separation study to provide the revised retail Jurisdictional Operating Income and Rate Base, which we used, along with the forecasted December 31, 2019 Capital Structure and Cost of Capital, to calculate the revised Operating Income and Revenue deficiency to get the revised proposed revenue increase amount, along with the associated revised uncollectible expense, public utility fee and current income tax amounts.

Ms. Diaz then performed the Cost of Service Study to get revised proposed jurisdictional revenue requirements by customer class. The jurisdictional revenue requirements by customer class that Ms. Diaz is supporting in this case for our proposed base rates that would be implemented in mid-2020 were then subtracted from these revised revenue requirements by customer class, to get the amount of the estimated Step 1 Revenue Requirement Adjustment by amount for each rate group. These amounts were divided by the forecasted kwh sales for 2020 to get the amount of the estimated Step 1 Rate Adjustment per kwh.

As explained in Section II., when implementing this Step 1 Adjustment in mid-2020, we will use this method with actual December 31, 2019 values of in-service net utility plant and property, and the resulting Step 1 Revenue Requirement Adjustment would be included in with other credits in our Credits

Rider, with the rates implemented at the same time as the approved base rates following the Commission order in this proceeding.

Q. WHAT WERE THE RESULTS OF THIS REVISED CALCULATION?

A. The estimated proposed retail revenues for purposes of calculating the Step 1 Revenue Requirement Adjustment were approximately $2.893 billion compared with $2.942 billion for the amount used to design the Company's proposed base rates (or approximately 98% of the proposed base rate revenue requirements), or a reduction of $49.6 million. This $49.6 million reduction is the estimated Step 1 Revenue Requirement Adjustment amount that would be included in the Credits Rider as an additional offset to the new base rates implemented with the Commission's order, if it were based on the actual December 31, 2019 data instead of forecasted data.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-I (DLD).

A. Petitioner's Exhibit 4-I (DLD) is a series of schedules supporting the calculation of the estimated Step 1 Rate Adjustment. Schedule RA1 shows the calculation of the estimated Step 1 Revenue Requirement Adjustment and rates by rate group. Schedule RA2 shows the Step 1 Revenue Requirements calculation, in the same format as Petitioner's Exhibit 4-D (DLD).

Q. PLEASE EXPLAIN PETITIONER'S EXHIBITS 4-J (DLD), 4-K (DLD) and 4-L (DLD).

A. Petitioner's Exhibit 4-K (DLD) Schedule RB1 shows the values of the December 31, 2019 rate base used in the development of the estimated Step 1 Rate

Adjustment, and Schedules RB2 through RB5 provide the Plant-in-Service detail. Petitioner's Exhibit 4-J (DLD) Schedule OPIN1 shows the revised Operating Income with the new depreciation, public utility fee, uncollectible expense and income tax values, with Schedules DA1 through DA7 showing the revised depreciation expense calculations. Petitioner's Exhibit 4-L (DLD) shows the December 31, 2019 Capital Structure and Cost of Capital used in the Step 1 Rate Adjustment development. Additional supporting workpapers CS13-DLD – CS18-DLD will also be filed.

VIII. RATE ADJUSTMENT RIDERS

A. IGCC Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS IGCC RIDER?

A. Consistent with the terms agreed to by the Settling Parties to the 2018 Settlement Agreement which was approved by the Commission in its June 5, 2019 final order in IGCC-17 ("IGCC-17 Order") ("2018 IGCC Settlement Agreement"), the Company has included Edwardsport plant investment and operating expenses in the base rates being proposed in this proceeding and is proposing to discontinue the tracking of Edwardsport investment and operating expenses in the IGCC Rider, effective with the implementation of new base rates resulting from this proceeding.[6][7] Accordingly the Company is proposing the elimination of the IGCC Rider at that time.

Q. DID THE COMMISSION'S IGCC-17 ORDER APPROVE THE 2018 IGCC SETTLEMENT AGREEMENT TERM THAT PROVIDED FOR BASE RATE TREATMENT?

A. The Commission's IGCC-17 Order left the issue of base rate treatment for Edwardsport investment and operating expenses to be decided in the Company's next base rate proceeding (*i.e.*, this proceeding). Specifically, the Commission stated on page 34 of the IGCC-17 Order:

> "Finally, we approve of the Settlement Agreement's provision that Duke Energy Indiana not file an IGCC Rider in 2019 or 2020, and will consider Duke Energy Indiana's request to include Edwardsport in base rates during our consideration of Duke Energy Indiana's next retail rate case filing."

The Company is herein requesting the Commission approve this base rate treatment for Edwardsport and discontinuation of the IGCC Rider.

Q. SHOULD THE COMMISSION APPROVE THIS RATEMAKING PROPOSAL FOR EDWARDSPORT COSTS AND THE ELIMINATION OF THE IGCC RIDER, HOW WILL ANY FINAL RECONCILIATION OF

---

[6] In addition to Duke Energy Indiana, the Settling Parties included the Indiana Office of Utility Counselor ("OUCC"), the Duke Industrial Group, and Nucor Steel-Indiana.

[7] As discussed in Section IV. C., in addition to the plant investment and operating expenses for Edwardsport being included in base rates, the Company has included the materials and supplies ("M&S") and fuel inventories in base rates. These inventories were not one of the items proposed and approved for tracking in the IGCC rider.

OPERATING EXPENSES UNDER THE TERMS OF THE IGCC RIDER TARIFF BE HANDLED?

A. The Company's proposal and the treatment agreed to by the Settling Parties to the 2018 IGCC Settlement Agreement is that a final reconciliation of the IGCC Rider will be made as part of the first practicable Environmental Compliance Cost Recovery ("ECR") rider ("ECR Rider") filing following the Commission's issuance of the order in this base rate proceeding. The calculation of the reconciliation will incorporate the 2018 IGCC Settlement Agreement O&M Caps for 2018 and 2019 ("Caps") to ensure that customers pay only for the lesser of actual O&M costs incurred in 2018 and 2019 (defined in the 2018 IGCC Settlement Agreement as operation and maintenance expenses, payroll taxes, property taxes, property insurance and net of the credit for operating expenses of the retired Edwardsport coal plant, but excluding fuel and depreciation) and the agreed upon retail jurisdictional Caps of $97.6 million for 2018 and $96.0 million for 2019.[8] Also pursuant to the terms of the 2018 IGCC Settlement Agreement, the reconciliation will also include the difference between the amount of O&M that Duke Energy Indiana recovers after January 1, 2020, via the IGCC Rider and the amount that Duke Energy Indiana is authorized to recover in this base rate proceeding for the same Edwardsport cost items. Further, no more than $10 million annually (or $5 million in each semi-annual ECR Rider filing) of costs associated with the IGCC Rider reconciliation will be included in the ECR Rider.

[8] Subject to the Force Majeure terms of the 2018 IGCC Settlement Agreement.

The Company shall continue to include the IGCC reconciliation amounts in future ECR Riders until the reconciliation amount (without carrying costs) is fully collected or refunded to customers.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS INCLUDED IN THE IGCC RIDER THAT WILL BE INCLUDED IN THE ECR RIDER UPON IMPLEMENTATION OF NEW BASE RATES?

A. Yes. IGCC Rider rates currently include an amount for amortization of retail jurisdictional operating costs incurred in excess of amounts being recovered through IGCC Rider rates from June 7, 2013 through August 2016 ("Regulatory Asset"). The initial amortization amount that was established pursuant to the 2016 IGCC Settlement Agreement in IGCC-15 was $20 million of annual amortization. The Commission's approval of the 2018 IGCC Settlement Agreement in its IGCC-17 Order reduced the amount to be included in IGCC Rider rates to $10 million of annual amortization over a three-year period beginning Cycle 1 of July 2019, after which three-year period the amortization will go back up to $20 million annually until the Regulatory Asset is fully amortized. The Settling Parties to the 2018 IGCC Settlement Agreement agreed that the Company would propose in its next base rate case that base rates be set using the original $20 million of annual amortization, which is what we have included in the development of base rate revenue requirements in this case. Along with that, to ensure that customers received the benefit of the entire $30 million reduction in amortization rates ($10 million annually for three years), the Settling Parties agreed that a $10 million annual credit would be included in the ECR rider (or $5 million in each semi-annual ECR Rider filing) to offset the $20 million in base rates until the total $30 million benefit of the 2018 Settlement Agreement reduction was refunded through rates. The direct testimony of Ms. Graft will discuss these IGCC Rider-related additions to the ECR Rider, among other proposed ECR rider changes.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS INCLUDED IN THE IGCC RIDER THAT WILL NOT BE BUILT INTO BASE RATES?

A. Yes. There are three IGCC facility tax incentive credit items that are currently included in the IGCC Rider that the Company has not included in its development of the proposed base rates in this proceeding. These include:

- A credit for the retail jurisdictional portion of the $15 million annual Indiana Coal Gasification Technology Investment Tax Credit ("State Tax Credit");
- A credit for the retail jurisdictional portion of the ten-year property tax abatement from Knox County; and,
- A credit for the retail jurisdictional portion of the thirty-year reimbursement due to designation of Edwardsport as a Tax Increment Financing ("TIF") District.

In addition, once the Company can utilize the $133.5 million federal Advanced Coal Investment Tax Credit ("Federal ITC") on its corporate consolidated federal income tax return, an additional credit for the retail jurisdictional portion of the annual ITC amortization was planned to be included in the IGCC Rider. This credit has not been included in the proposed base rates in this proceeding to ensure compliance with the federal income tax normalization requirements because the Company will not be able to utilize the credit until after the Test Period due to its current Net Operating Loss ("NOL") position for the Duke Energy Corporation Consolidated income tax return, as discussed in the testimony of Mr. Panizza.

Q. UNDER THE COMPANY'S PROPOSAL, HOW WILL CUSTOMERS RECEIVE THESE TAX INCENTIVE BENEFITS IF THE IGCC RIDER IS ELIMINATED?

A. The Company plans to include these tax incentive benefits as credits to customer rates in its Rider 67 Credits Rider, which I will discuss in more detail below.

Q. WHY ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING COSTS AND CREDITS CURRENTLY INCLUDED IN THE IGCC RIDER REASONABLE?

A. The Company's request is consistent with past practice in Indiana for capital riders to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. In Duke Energy Indiana's last base rate case in Cause No. 42359, the net book value of certain Qualified Pollution Control

Equipment plant that had been tracked in the Company's Standard Contract Rider No. 62 – Environmental Compliance Investment Adjustment was built into base rates. In Cause No. 43839, approved April 27, 2011, the Commission approved Southern Indiana Gas and Electric's request to include in base rates its investment and operating expenses related to certain Qualified Pollution Control Equipment and terminate the tariffs that were used to track these costs once base rates were eliminated, with a final reconciliation of operating expenses to be included via a remaining tracking mechanism, in addition to base rate inclusion with termination of the tariff for a third plant-in-service project that was previously tracked. As noted previously, the Settling Parties to the 2018 IGCC Settlement Agreement agreed that Duke Energy Indiana should petition in this base rate case to include Edwardsport investment and operating expenses in base rates and to discontinue the tracking of Edwardsport thereafter.

Additionally, excluding the IGCC Incentive Tax Benefit credits from base rates and moving them to Rider 67 is a transparent way to show parties that customers are indeed continuing to get these credits even though the cost of the plant and operating expenses that were previously in the IGCC Rider are now in base rates, particularly since we haven't been able to begin including the Federal ITC in the IGCC Rider and can't yet include it in base rates without violating federal income tax normalization rules due to Company's consolidated income tax return's current NOL position. Including the Federal ITC in Rider 67 as proposed by the Company when we can begin utilizing the credit will efficiently allow the Company to pass this benefit back to customers in a transparent way.

The Company has already begun using Rider 67 to pass back to customers the amortization of the unprotected EDIT that was created due to the reduction in federal income taxes resulting from the TCJA. The Company is also committed under the terms of the Settlement Agreement and August 22, 2018 Commission Order in Cause No.45032-S2 ("TCJA Settlement Agreement", "TCJA Order") to begin to use it for a twenty-year-plus amortization of protected EDIT beginning in January 1, 2020, so Rider 67 will need to continue to exist post-rate case. It's administratively more efficient for all parties and the Commission to combine all these credits into one rider, rather than continuing the IGCC Rider just to pass IGCC-related tax benefits back to customers. Additionally, Rider 67 is filed under Section 3 of the Thirty-Day Administrative Filing Procedures and Guidelines in 170 IAC 1-6 ("Thirty-Day Rules", "Thirty-Day Filing") rather than under a docketed proceeding, which is much more administratively efficient for parties and the Commission than continuing the IGCC Rider in a docketed proceeding, while still affording parties notice and the ability to object under the terms of the Thirty-Day Rules.

Further, the state IGCC ITC will end in 2022, as will the 10-year property tax abatement, so putting these into a rider rather than building into base rates is a practical way to enable the Company to adjust rates when the credits end. This is also consistent with how the Company is planning to adjust rates when the short term regulatory asset amortizations proposed to be included in base rates in this case end by including additional credits in Rider 67. This planned treatment includes the $20 million level being built into base rates for the Regulatory Asset amortization for IGCC discussed previously.

The $10 million annual Regulatory Asset amortization reduction being moved from the IGCC rider to the ECR rider is also a short-term reduction in expense, which will also end in 2022. So, rider treatment for it makes sense, and Settling Parties agreed to include it in the ECR Rider for that very reason.

B. TDSIC Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS TDSIC RIDER?

A. The Company is proposing to roll the net book value (original cost investment less accumulated depreciation) of in-service TDSIC plant as of the end of the Test Period into base rates. This includes the 80% of in-service plant that is eligible for inclusion in the TDSIC rider, as well as the 20% that is deferred for rate case recovery pursuant to Ind. Code § 8-1-39 ("TDSIC Statute").[9] Additionally, the Test Period level of property taxes will be included in base rates, as will the depreciation associated with the investment rolled in.

[9] In addition to the net book value of the 20% amount of in-service TDSIC plant, the Company is including in rate base the projected end of Test Period balances of deferred depreciation on the 20% of investment, as well as the 20% of deferred O&M and property taxes associated with the in-service projects, the associated post-in-service carrying costs on the deferred investment, and deferred financing costs on the O&M and property taxes deferred. The deferrals are all consistent with the TDSIC statute and previous Duke Energy Indiana TDSIC plan Commission Orders in Cause Nos. 44720, 44720 TDSIC-1, 44720 TDSIC-2, and 44720 TDSIC-4. Cause No. 44720 TDSIC-6 is currently pending. See Petitioner's Exhibit 4-F (DLD) for regulatory asset balances for these items that are being including in rate base.

At the time of implementation of the new base rates resulting from this proceeding, the TDSIC Rider will be revised to:

- remove the investment and property tax amounts included in base rates;
- recalculate the depreciation on the remaining investment using the new depreciation rates approved in this proceeding;
- change the 10% ROE used in the cost of capital calculation for the TDSIC Rider to the new ROE approved in this proceeding; and
- change the allocations to rate classes used in the calculation of rates to use the final approved Transmission and Distribution revenue requirements from this proceeding instead of the revenue requirements from Cause No. 42359.

This proposed treatment and changes are in accordance with the terms of the TDSIC Settlement Agreement – term 7e. on page 6:

> "At the time of the subsequent base rate case, the Settling Parties agree that the T&D improvements in-service by the rate base cut-off date will, (subject to a normal prudence review in the TDISC (*sic*) Rider proceedings), be included in rate base and subject to the ROE and allocation factors that are ultimately determined by the IURC in such retail base rate case. Similarly, the 20% of the T&D improvements that have been deferred with carrying costs will be included in retail rates and rate base and any AMI deferrals will be included in rates. If there remain years in the 7-year T&D Plan (or a new T&D plan) after the subsequent retail base rate case order, all caps will remain in effect for 2016 – 2022 and any TDSIC Rider would be adjusted to use the new ROE and allocation factors approved in the subsequent retail base rate case."

Finally, the revenue conversion factors used to calculate amounts in the TDSIC rider will reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax, if approved.[10]

Q. SHOULD THE COMMISSION APPROVE THIS RATEMAKING PROPOSAL FOR TDSIC INVESTMENT, HOW WILL IT AFFECT CALCULATIONS IN THE CONTINUING TDSIC RIDER FILINGS?

A. The Company plans to continue to report total annual and cumulative investment totals in its TDSIC plan and rates filings for purposes of determining amounts to include in the TDSIC Rider pursuant to the TDSIC Settlement Agreement which established caps on the cumulative amount of investment that can be included for rider recovery for each year of the seven-year plan covering 2016 – 2022. For example, for Calendar Year 2021, the cumulative cap amount is $1.155 billion. If investment up to the full $0.928 billion cumulative cap amount for 2020 was put in base rates, the $0.928 billion would be subtracted from the $1.155 billion cap amount, leaving $0.227 billion additional in-service investment that could be included in the rider filing covering 2021. If only $0.900 billion was put in base rates, it would be subtracted from the $1.155 billion cap amount leaving $0.255 billion that could be included in the rider. In other words, the amounts included

[10] The Direct Testimony of Ms. Graft will explain the Company's proposal to include URT on customer bills in lieu of including it as a cost of service item and will support the *pro forma* adjustment to remove URT from the cost of service.

in the rider plus the amounts included in base rates will not exceed the approved cumulative caps for each remaining year of the 7-year plan.

Similarly, to enable comparisons of forecasted plan amounts to actuals by projects as is done in the rate filings, business witnesses in the post-base rate case TDSIC filings will continue to present total cumulative amounts for each TDSIC project. For calculation of return purposes, the amount in base rates will be subtracted from the total plan investment so that only 80% of the incremental amount not currently earning a return in base rates will earn a return in the rider. Depreciation and property taxes will then be calculated on the incremental amount of investment included in the rider, consistent with the method currently used in the Company's ECR rider related to the QPCP plant that was rolled into base rates in the Company's last base rate case.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS INCLUDED IN THE TDSIC RIDER THAT WILL NOT BE BUILT INTO BASE RATES?

A. Yes. The Company is proposing that TDSIC O&M expense and post-in-service carrying costs not be included in base rates, but rather continue to be tracked in the TDSIC Rider. This is because, for TDSIC, the project-related O&M is non-recurring and variable in nature and the O&M for the inspection-based projects can also fluctuate depending on the number of inspections included in each plan year. The post-in-service carrying costs are also non-recurring and variable in nature, as in each annual filing the costs accrued in the prior year are included for recovery over the one-year period the rider rates will be in effect, and the next year the costs accrued will be for a different set of projects, with differing costs, in-service dates, etc. for each year of the 7-year plan. Additionally, the amortization of the current balance of unamortized Plan Development Costs was not included in base rates because the current balance should be fully amortized by the end of the Test Period. Should the Company incur any additional costs for updated risk analyses for plan update filings, these costs will be included in normal course of business for recovery via the TDSIC Rider.

Q. WHY ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING TDSIC INVESTMENT AND COSTS CURRENTLY INCLUDED IN THE TDSIC RIDER REASONABLE?

A. As I discussed in relation to the IGCC Rider, the Company's proposal is consistent with past practice in Indiana to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. The Company's proposed treatment is also in accordance with the terms of the TDSIC Settlement Agreement and the TDSIC Statute. To continue to track the 80% portion of O&M expense, post-in-service carrying costs, and any additional Plan Development costs in the TDSIC rider, along with the 80% portion of all incremental new investment and related depreciation and property tax, is a reasonable way to recover the non-routine and variable TDSIC costs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE TDSIC RIDER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the amounts included in base rates and adjust the ROE, revenue conversion factors, and allocation factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and rider rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT TDSIC RIDER TARIFF?

A. Yes. The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering, as well as reflecting an update in ROE language and allocation factors to refer to the current proceeding. Copies of the red-lined and clean revised tariff sheet pages containing the tariff language for the TDSIC Rider will be attached to my testimony as Petitioner's Exhibit 4-M (DLD) and 4-N (DLD). They will also be included with the complete set of base rate and other rider tariffs that will be filed as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). A complete set of all revised tariff pages will be filed for Commission approval with the Step 1 Base Rate Phase-in Compliance filing in mid-2020, reflecting the changes in the then-current rates due to the Commission's findings related to base rates, including the use of the allocation factors approved in this proceeding.

C. <u>EE Rider</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS EE RIDER?

A. As discussed by Duke Energy Indiana witnesses Mr. Brian P. Davey, Mr. Bailey, Dr. Daniel G. Hansen, and Ms. Diaz, the Company is proposing a new revenue decoupling mechanism ("RDM") in this proceeding for Commission consideration. The nature and extent of the changes to the EE Rider will depend on whether the RDM is approved. The reason for this is that, in addition to recovery of energy efficiency ("EE") program costs and a performance incentive that may be earned, the Company's EE rider includes a provision for life of EE measure recovery of revenues that otherwise would have been received to cover the Company's fixed costs, but for the successful implementation and energy savings resulting from the energy efficiency programs offered by the Company to its customers ("lost revenues"), as measured by an Evaluation, Measurement and Verification ("EM&V") process. This provision is often referred to as a lost revenue recovery mechanism or "LRAM".

The Company's proposed RDM would replace the LRAM mechanism for recovery of lost revenues resulting from the Company's EE programs for those customers who are a part of the proposed RDM. Dr. Hansen and Ms. Diaz will provide more details on the RDM and the specific rate classes proposed for the RDM, which I will refer to generally as the Residential and Commercial customer groups. With approval of the RDM, EE program costs (including the cost of EM&V) and performance incentives would still be included in the EE Rider for the Residential and Commercial customers, along with any reconciliations or re-reconciliations of lost revenues due to the Company's approved retrospective application of new EM&V received related to programs offered to these groups up through the implementation date of the new base rates. Other customer groups would continue to have all three components (program costs, shareholder incentives, and lost revenues) recovered via the EE Rider (subject to the customer's opt out status and the changes that will result due to the implementation of new rates with or without the RDM). I will further discuss these changes below.

Q. SHOULD THE COMMISSION APPROVE THE RDM RATEMAKING PROPOSAL, HOW WILL IT AFFECT CALCULATIONS IN THE CONTINUING EE RIDER FILINGS?

A. As noted above, with approval of RDM, the items included in the EE Rider for the Residential and Commercial customer groups will exclude lost revenues for energy savings resulting from Company-sponsored EE programs going forward from the time of rate implementation.

As approved in the Commission's Order in Cause No. 43955 and subsequent Orders in Cause Nos. 43079 DSM-6, 44441 ("Opt Out Order"), 43955 DSM-1 through DSM-5, and most recently in 43955 DSM-6 (collectively, the Company's EE Orders), all customers and rate classes are charged for the cost of a vintage year's EE programs to the extent they are or were eligible to participate in the programs offered for that period.[11] The ratemaking model approved by the Commission for the EE Rider provides that residential customers, as a group, pay

[11] Costs for a vintage year's programs may extend beyond that vintage year or the time customers were eligible to participate in the programs, such as in the case of persisting lost revenues or for the costs of EM&V performed in a subsequent year for a prior vintage year's programs.

for the cost of residential programs (*i.e.*, all customers in the residential group pay the same rate per kWh) and non-residential customers, as a group, pay for the cost of non-residential programs for which they are or were eligible to participate in (*i.e.*, all participating customers in the non-residential group pay the same rate per kWh and all customers in each of the opt-out/opt-in groups pay the same rate per kWh).[12] Costs are allocated among the non-residential group to participants and each of the opt out/opt-in groups on the basis of kwh.

Because the Commercial rate group that is proposed for inclusion in the RDM is part of the larger non-residential group for EE rider rate development, approval of the RDM will require us to modify the non-residential rate development, similar to what is currently done for each of the opt out/opt in groups currently, by pulling the Commercial group out as a separate category for rate development that will get their share of total non-residential program costs, EM&V, performance incentive and reconciliations allocated on the basis of their share of non-residential kwh. A separate rate would then be computed for them by taking their allocated share of costs and dividing by their kwh, just as we do for the various non-residential opt out groups today.

These changes would only be implemented in the EE Rider if the proposed RDM is approved.

[12] Duke Energy's large non-residential customers meeting certain criteria became eligible to opt out of eligibility to participate in EE programs in April 2014 following the Opt Out Order. Each year such customers meeting certain criteria can opt out of the next year's programs or opt back in. That has necessitated developing separate rates for each of these groups of customers, depending on the year or years they opted out or opted back in.

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS EE RIDER, WITHOUT RESPECT TO APPROVAL OF THE RDM?

A. The Company is proposing to change the numbering of the EE Rider from Standard Contract Rider No. 66-A to No. 66. Prior to implementation of the EE Rider following the Commission's December 9, 2009, order in generic EE proceeding in Cause No. 42693 (Phase II), the Company had a DSM rider under Standard Contract Rider No. 66 that recovered program costs only. Due to a period in which both the old DSM rider and the new EE rider needed rates for customers (due to remaining reconciliations required for the old DSM rider which used a different billing construct than the EE Rider), a separate rider number was used for the EE Rider. Following this base rate case there is no need to maintain both numbers, so we will reuse No. 66 for the EE Rider.

In addition, at the time of implementation of the new base rates resulting from this proceeding, the EE rider will be revised to change the revenue conversion factors used to calculate revenue requirements to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax, if approved.

Q. IS THE COMPANY PROPOSING TO EMBED ANY LEVEL OF COSTS IN BASE RATES FOR PROGRAM COSTS, INCLUDING ADMINISTRATIVE OVERHEADS, OR SHAREHOLDER INCENTIVES?

A. No. Consistent with the treatment approved in the Company's last rate case for its DSM rider that preceded the current EE Rider, the Company is proposing to remove all EE program costs, including administrative and EM&V costs, and all shareholder incentives from the cost of service and track these costs in the EE Rider from the zero base.

Q. PLEASE EXPLAIN WHAT WILL HAPPEN WITH THE LOST REVENUES CURRENTLY INCLUDED IN THE EE RIDER WITH THE IMPLEMENTATION OF NEW BASE RATES.

A. There will be several impacts. Because the Company is using forecasted sales for 2020 in developing the new base rates:

- The persisting lower sales that resulted from Company EE programs offered up through year-end 2019 will be completely reflected in the forecasted sales used for setting new base rates. Therefore, the persisting lost revenue amounts for calendar years 2012 through 2018 and any lost revenue amounts for 2019 vintage programs in then-current EE Rider rates will be reset to zero in the rider and remain zero in future rider filings.
- The 2020 impact of lower sales that result from Company EE programs offered in 2020 will be reflected in the forecasted sales. Therefore, any lost revenue amounts for 2020 vintage programs will be reset to zero in the rider for the remainder of 2020.
- However, the 2020 impact of lower sales reflected in the 2020 forecasted sales does not fully reflect the annual sales loss that will occur as a result of 2020 energy efficiency programs, because all 2020 EE program participation was not forecasted to begin (and will not begin) on January 1, 2020. Customers

decide to participate and begin installing EE program measures throughout the calendar year and the Company assumes for forecasting purposes that customers participate in EE in equal amounts for each month throughout the year. It is not until year end that all participation has occurred and all measures have been installed for the calendar year.

For this reason, the actual sales reductions the Company will experience in 2021 as a direct result of the 2020 Company-sponsored EE programs will be larger as the amounts that were included in the 2020 forecast used for base rate development. This creates the need for a level of lost revenues for 2020 programs to be included in the EE rider beginning in 2021 through the life of the measures in order for the Company to have the opportunity to earn its allowed return considering the full extent of the reductions in sales resulting from its 2020 EE programs. The Commission has ruled in its EE Orders it is appropriate to recover lost revenues in the EE Rider for the sales reduction impacts from Company-sponsored EE programs. So, beginning with rates that incorporate the forecast for 2021 programs, the incremental sales reduction impacts achieved from 2020 EE programs will be used to develop persisting lost revenues to be included in the EE Rider for customers eligible to participate in the 2020 EE programs (and not included in an RDM, if approved.)

Additionally, after the new base rates are implemented, the prices that are used to calculate the lost revenue amounts included in the EE rider will reflect the fixed costs approved for recovery in this base rate proceeding rather than using Cause No. 42359 costs to price the lost revenues.

Q. WILL CUSTOMERS, INCLUDING NON-RESIDENTIAL CUSTOMERS WHO HAVE OPTED OUT OF PARTICIPATING IN ENERGY EFFICIENCY PROGRAMS AT THE TIME OF THE RATE CASE, CONTINUE TO BE BILLED OR CREDITED THROUGH THE EE RIDER AFTER THE RATE CASE FOR EE RIDER RECONCILIATIONS FOR PRIOR YEARS?

A. Yes. The Commission has approved the Company's EE Rider reconciliation and EM&V processes and timing, most recently in its last three-year plan approved in DSM-4, including the retrospective application of EM&V for lost revenue reconciliation purposes. This can result in re-reconciling prior years when an EM&V can't be done annually due to the need to get a larger sample size.

For Residential customers, vintage years 2012 – 2014 have been fully reconciled in the rider. There is still outstanding EM&V for the remaining vintage years that will result in additional reconciliations in the future.

For Non-Residential customers, vintage years 2012 – 2015 have been fully reconciled in the rider. So, for the eligible customers who opted out of EE programs effective April 15, 2014 or January 1, 2015, and who have not opted back in as of the time of implementation of base rates, there will be no further reconciliation of EE rider costs required, and their EE rider rate will remain zero if they remain opted out. Once all EM&V for additional vintage years has been received and reflected in the final EE Rider reconciliation for that vintage year, additional customers who have opted out and not opted back in will see their rider rate go to zero if they remain opted out. All other Non-Residential customers will continue to see additional reconciliations in the future.

Q. WHY ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING THE EE RIDER REASONABLE?

A. Keeping all energy efficiency costs in the EE Rider rather than embedding some level in base rates is appropriate given the statutory requirement to propose plans consistent with each Integrated Resource Plan, which are required to be updated every three years. This requirement means plans can and will change, and the levels of costs will change. Additionally, participation and results may vary materially each year, making the EE Rider rates volatile. Further, having all EE costs in a rider gives participating and non-participating customers a full picture of their share of the costs of the Company's EE programs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE EE RIDER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the lost revenue amounts and adjust the revenue conversion factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and rider rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT EE RIDER TARIFF?

A. Yes. The Company is making some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs, resetting the tariff numbering, as well as removing an outdated table and replacing it with revised language regarding the ongoing annual opt out/opt in deadlines and timing, and updating the items included in the revenue conversion factors to reflect the Company's URT proposal in this proceeding. In addition, the rate calculation formulas and variables will need to be changed if the Company's RDM proposal is approved, because lost revenues will no longer be included in the EE Rider for Residential and Commercial Customers. Copies of the red-lined and clean revised tariff sheets for the EE Rider assuming the Company's RDM proposal is approved will be attached to my testimony as Petitioner's Exhibit 4-O (DLD) and 4-P (DLD). Also attached as Petitioner's Exhibit 4-Q (DLD) and 4-R (DLD) are copies of the red-lined and clean revised tariff sheets for the EE Rider assuming RDM it is not approved and Lost Revenues instead remain in the EE Rider for Residential and Commercial customers. The proposed EE Rider tariffs will also be included with the complete set of base rate and other rider tariffs that will be filed as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). A complete set of all revised tariff pages will be filed for Commission approval with the Step 1 Base Rate Compliance filing in mid-2020, reflecting the changes in the then-current rates due to the Commission's findings related to base rates.

D. <u>Credits Rider</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS CREDITS RIDER?

A. In addition to the ongoing TCJA credit currently in the Credits Rider for unprotected EDIT amortization, pursuant to the TCJA Settlement Agreement, a one-time $1.9 million credit will be included in the Rider in January 2020 and the ongoing additional credit amortization of protected EDIT will also begin in January 2020. The TCJA Settlement Agreement also included a provision regarding the deferral of the 2018 and 2019 amounts of protected EDIT amortization, with subsequent rate recovery provisions to be proposed in this proceeding. The Company proposes to include this amortization of the deferred amount in the Credits Rider with the additional protected EDIT amortization, over the same remaining lives of the assets using the Internal Revenue Code Average Rate Assumption Method ("ARAM"), also discussed by Mr. Panizza.

As discussed in Section VIII. A. of my testimony covering the IGCC Rider, in addition to the TCJA related credits that are currently or will be included in the rider pursuant to the TCJA Settlement Agreement, the Company is proposing to include certain IGCC facility tax incentive credits that are currently included in the IGCC Rider or were planned to be included in the IGCC Rider (namely, state and federal ITC credits and property tax incentives).

In addition, as discussed previously, the Company plans to include additional credits in this rider as the regulatory assets for which amortization is being included in base rates become fully amortized.

Further, as discussed previously in Section II. of my testimony, the Credits Rider is planned to be used during the first step of implementing the new base rates by crediting customers (upon review and approval by the Commission in a compliance filing) with the difference between what final base rates are using the proposed forecasted Test Period revenue requirements, reflecting used and useful plant in-service as of December 31, 2020, and what they would be using the known actual used and useful plant in-service as of December 31, 2019 ("Step 1 Rate Adjustment"). This will ensure that customers only pay for used and useful plant during this Step 1 period from mid-2020 before final December 31, 2020 used and useful plant in-service amounts are known and until the Step 2 rates are implemented. As explained previously, the Company will then calculate final revenue requirements using actual December 31, 2020 used and useful plant in-service. If this amount is more than the amount built into the base rates implemented mid-2020 using the forecasted December 31, 2020 used and useful plant in-service, then the Step 1 Rate Adjustment will be removed from the Credits Rider (upon review and approval by the Commission in a compliance filing). If it is less, the difference will be computed and customers will receive the final Step 2 revised amount for the Rate Adjustment via the Credits Rider until the implementation of revised rates in the Company's next base rate case (again, upon review and approval by the Commission in a compliance filing). This second step will ensure that customers continue to pay for used and useful plant only as a result of the final base rates approved during this proceeding, coupled with this Step 2 Rate Adjustment in the Credits Rider.

In addition to the inclusion of the additional TCJA credits, the credits previously included in the IGCC Rider for the IGCC facility tax incentive benefits and the Two-Step Rate Adjustment, at the time of implementation of the new base rates resulting from this proceeding in mid-2020, the Credits Rider will also be revised to:

- remove the credit to remove the 1994 Cinergy Merger Costs which is currently in the rider (see additional discussion of this item below);
- change the allocations to rate classes used in the calculation of revenue requirements for the TCJA credits to use the final approved net book value of in-service plant from this proceeding instead of from Cause No. 42359;
- add separate allocations to rate classes to be used in the calculation of revenue requirements for the credits for the IGCC facility tax incentive benefits using the production demand allocators from this proceeding (the benefits are currently being allocated in the IGCC Rider using the production demand allocators from Cause No. 42359); and
- include the calculated revenue requirements differential by rate class for the Two-Step Rate Adjustment.

Under the Company's proposal, as regulatory assets included in base rates become fully amortized, the Company intends to review the materiality and nature of the cost being amortized and determine the appropriate allocation method to be used for the additional credit in the rider.

Q. SHOULD THE COMMISSION APPROVE THIS RATEMAKING PROPOSAL, HOW WILL IT AFFECT CALCULATIONS IN THE CONTINUING CREDITS RIDER FILINGS?

A. Because the rider will use different allocation methods for its three components (TCJA credits, IGCC tax incentive benefits, and Two-Step Rate Adjustment), the calculation of the rider will change slightly. Today the rider uses two different allocation methods for the Cinergy Merger and TCJA credits, allocating each separately, then adding the revenue requirements by rate class together and dividing by kwh to get the rate. We will merely replace the Cinergy Merger component with the IGCC tax incentive benefits component and use the production demand allocator for this component and add in the Two-Step Rate Adjustment to the total revenue requirements, then divide by kwh to get the rate.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS CURRENTLY INCLUDED IN THE CREDITS RIDER THAT WILL NOT BE BUILT INTO BASE RATES?

A. Yes. As noted previously, the rider currently includes a credit to remove from rates the annual amortization of the 1994 Cinergy Merger Costs that were embedded in the base rates approved in Cause No. 42359, but which were fully amortized on the Company's books effective June 2008. As these costs are not included in the cost of service for the Test Period, this credit will no longer be necessary once base rates are implemented, so it will be removed from the Credits Rider, but not built into base rates.

Q. WHY ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING THE CREDITS RIDER REASONABLE?

A. Continuing the Credits Rider is consistent with the requirements under the terms of the TCJA Settlement. As I discussed in relation to the IGCC Rider, continuing to track the IGCC facility incentive tax benefits provides transparency that the credits are indeed being provided to customers, even with the elimination of the IGCC Rider, while doing so in an already existing rider with administrative benefits due to being filed under the Thirty-Day Filing Rules. It also provides a transparent and administratively convenient means to ensure customers are only charged for used and useful plant as a result of the use of a forecasted Test Period in this base rate proceeding without creating a new rider (*i.e.*, the Two-Step Rate Adjustment). Having it available will also enable the Company to include additional credits when shorter term regulatory asset amortizations end prior to the next base rate case, allowing customers to benefit sooner in a planned way.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE CREDITS RIDER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to incorporate the changes discussed. This will be done concurrently with filing the new base rate tariffs, with both base rates and rider rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT CREDITS RIDER TARIFF?

A. Yes. The Company is proposing some cosmetic and format changes to get more consistency across its various rider and rate tariffs, including the addition of a "Calculation of Adjustment" section in this tariff and resetting the tariff numbering, as well as reflecting an update in language to reflect the components to be included in the Credits Rider going forward. In addition, the Company proposes to rename Rider 67 as the "Credits Adjustment" going forward.

Copies of the red-lined and clean revised tariff sheets for the Credits Rider will be attached to my testimony as Petitioner's Exhibit 4-S (DLD) through 4-T (DLD). They will also be included with the complete set of base rate and other rider tariffs that will be filed as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). A complete set of all revised tariff pages will be filed for Commission approval with the Step 1 Base Rate Phase-in Compliance filing in mid-2020, reflecting the changes in the then-current rates due to the Commission's findings related to base rates, including the use of the allocation factors approved in this proceeding.

IX. ACCOUNTING TREATMENT, DEFERRAL AND COST RECOVERY REQUESTS

A. Remaining Net Book Value of Wabash River Unit 6

Q. WHAT ACCOUNTING AND RATEMAKING TREATMENT IS THE COMPANY REQUESTING IN RELATION TO WABASH RIVER UNIT 6?

A. The Wabash River Station coal units, including Unit 6, were retired in 2016 due to economics after 48 years of providing service to customers, given the cost of complying with several federally mandated environmental rules, as discussed in the testimony of Duke Energy Indiana witness Mr. Keith B. Pike. Wabash River Units 2 – 5 were at the end of their life, so were accounted for as a normal retirement, an accounting term discussed earlier in my testimony in Section IV. C. Wabash River Unit 6, however, had a retirement date in the last approved depreciation study of 2028. That, along with the remaining net book value of the unit, factored into the Accounting Department's decision that normal retirement accounting could not be used for Wabash River Unit 6 (the accounting that occurs within the various plant FERC accounts at the end of an asset's life, as explained previously).

However, because Wabash River Unit 6 was used and useful plant that was included in base rates at the time of its retirement, the Company moved the remaining net book value of the unit from plant-in-service and accumulated depreciation accounts to a regulatory asset account. The Company continued to reduce the regulatory asset with amortization in the amount of the depreciation included in base rates for the unit and certain costs of removal were charged to the regulatory asset, as would have been done if the amounts were still in plant accounts instead of a regulatory asset.

The Company requests that the forecasted 2020 balance of the regulatory asset be included in rate base and that the cost of the remaining asset be recovered via amortization over the remaining life through the unit's 2028 expected retirement date in the approved depreciation study that was effective at the time of the unit's retirement.

Q. WHY IS THIS REQUESTED ACCOUNTING AND RATEMAKING TREATMENT REASONABLE?

A. The requested accounting and ratemaking treatment is the same cost recovery construct as for any remaining net book value of Wabash River's retired sister units and is no different than what would have occurred for Wabash River Unit 6 if the unit had been closer to its retirement date at the time it was retired – it's just that the costs are included in a regulatory asset account rather than a plant account. This is consistent with the historical Indiana regulatory practice of approving depreciation rates that are intended to cover both the cost of the plant that provided service as well as the cost of removal at the end of the plant's life, and of reserve transfers and allocations that are done after review in a depreciation study to ensure any remaining costs after retirement are fully covered. It's normal ratemaking treatment for retired plant that has been used and useful in reliably serving the Company's retail customers, even though the Company's accounting practices moved the costs from a plant asset account to a regulatory asset account.

B. <u>Coal Ash Remediation and Closure Costs</u>

Q. WHAT ACCOUNTING, DEFERRAL AND COST RECOVERY REQUESTS IS THE COMPANY REQUESTING IN RELATION TO

COAL ASH REMEDIATION AND CLOSURE COSTS ("COAL ASH COSTS")?

A. As described in detail in the testimony of Duke Energy Indiana witness Mr. Timothy J. Thiemann, the Company has incurred, is incurring and will be incurring various types of coal ash costs at multiple locations, under two basic environmental compliance rules: 1) a federally-mandated rule, the U.S. Environmental Protection Agency ("EPA") Coal Combustion Residuals ("CCR") rule, that requires approval under a state implementation plan which is under the purview of the Indiana Department of Environmental Management ("IDEM"); and 2) Indiana's Solid Waste Regulations, also under the purview of IDEM. He also explained that the EPA is currently in the process of promulgating new or revised rules addressing a D.C. Circuit Court decision which vacated and remanded certain portions of the 2015 rule. Because of these differing factors and timelines, the Company's requested accounting, deferral and cost recovery request for Coal Ash costs is not a "One-Size-Fits-All" approach. I will discuss the various components of the request and ratemaking treatment used in developing the proposed rates in this case. In general, I will discuss it in terms of "CCR Projects" and "IDEM Projects", categories based on the environmental compliance rules that govern the remediation or closure at each coal ash impoundment at each site.

Q. HOW HAVE THE COAL ASH COSTS THAT HAVE BEEN INCURRED BEEN ACCOUNTED FOR BY THE COMPANY?

A. If these costs weren't considered a legal obligation under ARO accounting, they would have been accounted for as a cost of removal that would be charged to a FERC 108 account to make up the final costs for a generating plant in its plant accounts:

Table 11

FERC ACCOUNT		TYPE OF COST OR CREDIT	AMOUNT RECOVERED THROUGH CUSTOMER RATES
101		Utility Plant in Service	$ 100,000
108		Accumulated Depreciation Recovering the Cost of the Plant via Depreciation Expense	(100,000)
108		Accumulated Depreciation Recovering the Expected Cost of Removal Net of Salvage ("COR") via Depreciation Expense	(10,000)
108		Any Salvage Value Upon Retirement/Dismantling	(1,000)
108		Actual Cost of Removal	$ 11,000
Total	=	Net Book Value	$ -0-

As I discussed previously in Section IV. C., depreciation rates are traditionally set for regulated utilities such that they are intended to cover the cost of the plant, plus any cost of removal less salvage value remaining at the end of the life of the plant, as illustrated above. The coal ash remediation and closure costs are properly considered cost of removal, dismantling and decommissioning of utility electric plant, and had the current environmental rules been foreseen and the current closure plans been developed at the time of the last depreciation study, the costs could have been estimated as a part of the decommissioning study and included in the depreciation rates, as some other Indiana utilities have done. However, they were not, and the depreciation study included a much lower level of coal ash costs in the cost of removal than what the Company has incurred to date and is forecasting to incur in the future under the current environmental rules governing the remediation and closure.

Because the coal ash costs that have been incurred by the Company are required due to the federal or state rules and meet the requirements for ARO Accounting under GAAP and FERC Accounting Guidance under Rule 631, the Company has separated out the costs from the Accumulated Depreciation Reserve FERC account 108 and instead accumulated the costs in a Regulatory Asset, net of the amounts customers have paid via depreciation rates for the coal ash portion of the estimated cost of removal that was included in current depreciation rates via a transfer from the 108 account where it was initially recorded. The Company believes this regulatory asset accounting treatment is appropriate and supported by the past practice in Indiana of recovery of both plant costs and cost of removal costs via depreciation rates.

Q. WERE ANY OF THESE COAL ASH COSTS INCLUDED IN RATE BASE IN THIS PROCEEDING?

A. Yes. The Company has included in a separate Coal Ash ARO Regulatory Asset Account (account number 182471) ("Coal Ash Regulatory Asset") the coal ash costs incurred from April 2015 when the CCR rule was promulgated through December 2018 for both CCR Projects and IDEM Projects, net of accumulated amounts that were recovered in depreciation rates for coal ash up through December 2018. The Coal Ash Regulatory Asset amount included in base rates also excludes any costs that were charged to the same regulatory asset accounting related to the Company's Phase 1 CCR projects that were approved under the Federal Mandate Statute for timely cost recovery in the Company's ECR Riders in Cause No. 44765. As noted before, but for the Company's ARO accounting, the costs the Company included in base rates in the Coal Ash Regulatory Asset would have been included as a cost of the plant assets included in base rates which are being depreciated. The Company's ARO accounting treatment for these costs and its proposed ratemaking for the costs has not increased nor decreased the amount that would have been included in base rates in this proceeding.

Q. IS THE COMPANY FORECASTING TO INCUR ANY ADDITIONAL COAL ASH COSTS BETWEEN DECEMBER 2018 AND THE END OF THE FORECASTED TEST PERIOD, DECEMBER 2020?

A. Yes. As discussed by Mr. Thiemann, the Company will incur additional coal ash costs during this time.

Q. HAS THE COMPANY INCLUDED THE COAL ASH COSTS FORECASTED TO BE INCURRED IN 2019 AND 2020 IN BASE RATES?

A. Yes, but only costs associated with the IDEM Projects that have approved closure plans (Gibson East Ash Pond and Dresser Station) have been included in base rates for these periods. As discussed by Mr. Thiemann, the Company will incur additional coal ash costs during this time for other IDEM and CCR Projects, but because the closure plans have not yet been approved, the Company is not including these forecasted costs in rate base in this case. Rather, as discussed below the Company is proposing continued deferral with carrying costs for these future coal ash costs.

Q. WHAT AMORTIZATION PERIOD IS PROPOSED FOR THE COST RECOVERY OF THE COAL ASH COSTS INCLUDED IN BASE RATES IN THIS PROCEEDING?

A. The Company is proposing amortization of the costs over eighteen (18) years consistent with the remaining life of the last operating coal unit at Gibson Station, as indicated in the updated depreciation study in this proceeding.

Q. WHAT ACCOUNTING TREATMENT IS THE COMPANY REQUESTING IN THIS CASE FOR THE ADDITIONAL COAL ASH COSTS FORECASTED TO BE INCURRED IN 2019 AND 2020 AND POST 2020 AT FACILITIES OTHER THAN THE GIBSON EAST ASH POND AND DRESSER STATION?

A. The Company is requesting authority to continue to defer these costs, as well as post-2020 costs for all IDEM and CCR Projects, in a regulatory asset for recovery in a future base rate case or, for the CCR projects, in a rider following a separate filing for authority under the Federal Mandate Statute.

Q. PLEASE PROVIDE AN OVERVIEW OF COST RECOVERY FOR FEDERALLY MANDATED REQUIREMENTS UNDER THE FEDERAL MANDATE STATUTE.

A. Indiana Code § 8-1-8.4-7 (c) provides for recovery of Commission-approved federally mandated costs that an energy utility incurs in connection with an approved compliance project undertaken as a result of federally mandated requirements. Indiana Code § 8-1-8.4-7(c)(1) provides that "Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs."[13] Pursuant to Indiana Code § 8-1-8.4-4, federally mandated costs include "capital, operating, maintenance, depreciation, tax, or financing costs." Indiana Code § 8-1-8.4-7(c)(2) provides that the remaining "Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission." Indiana Code § 8-1-8.4-7(c)(3) further provides that "Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification

[13] Indiana Code § 8-1-8.4-7(c)(1) also provides that the Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of Indiana Code § 8-1-2-42(d)(3) and Indiana Code § 8-1-2-42(g)(3), also referred to generally as the fuel clause earnings test.

by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission."

Q. IS THE COMPANY REQUESTING ANY ADDITIONAL ACCOUNTING AND RATEMAKING RELIEF IN THIS CASE FOR COAL ASH COSTS?

A. Yes, the Company is requesting that the Commission find the CCR Projects to be federally mandated projects under the Federal Mandate Statute and eligible to receive timely recovery of the costs incurred through December 2018 for the CCR Projects and the financing costs it has incurred or is forecasted to incur in relation to the December 2018 balance of costs for the CCR Projects.

Accordingly, the Company has computed the financing costs at its applicable weighted average cost of capital associated with the cost of the CCR projects included in the regulatory asset to be included in base rates in this proceeding and has forecasted the amount of 2019 and 2020 financing costs on both the projects and the accrued financing costs through December 31, 2020. The forecasted Test Period ending balance of these accrued financing costs has been included as a regulatory asset, to be recovered over the same period requested for the coal ash assets included in base rates in this proceeding – 18 years. In addition, the Company requests authority to continue to defer financing costs on the post-December 2018 CCR Projects expenditures and the balance of deferred carrying costs not in base rates until they are included in future retail rates.

Additionally, the Company is requesting authority to defer carrying costs (*i.e*., financing costs) at the weighted average cost of capital approved in this base rate proceeding on the additional costs incurred for the IDEM Projects above the amount included in base rates until they can be included in base rates.

Q. WHY IS THIS REQUESTED ACCOUNTING AND RATEMAKING TREATMENT REASONABLE?

A. The requested base rate cost recovery, with both return on and of the costs, is the same ratemaking treatment as the costs would have received if they had been treated as a normal retirement and is consistent with historical Indiana practice for regulated utilities of cost recovery for reasonable and necessary generating station costs of removal such as these. In addition, for the CCR Projects, it is consistent with recovery of Federally Mandated projects in a base rate case.

C. <u>Edwardsport Major Planned Outage Normalization Reserve</u>

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST REGARDING THE EDWARDSPORT MAJOR PLANNED OUTAGE NORMALIZATION RESERVE?

A. As discussed in Section VI. in explaining Petitioner's Exhibit 4-E (DLD), Schedule OM16, the Company removed $46,401,000 from forecasted Test Period production maintenance costs for the incremental cost of the spring 2020 major planned outage at Edwardsport Station. Although these costs were removed for setting base rates because they weren't reflective of an ongoing yearly level of planned outage maintenance expense, they are reflective of the level of reasonable and necessary incremental planned outage maintenance expense that will occur at Edwardsport approximately every seven years, as supported in the testimony of Mr. Gurganus. The Company therefore proposes that the retail portion of the production maintenance expense that is actually incurred for the 2020 spring major planned outage in excess of the remaining (after the *pro forma* adjustment) $4,730,902 amount included in base rates for ongoing Edwardsport planned outage maintenance expense up to the $46,401,000 forecasted amount be deferred in a regulatory asset account for amortization and cost recovery over seven years, the approximate time period between major planned outages. In this way, revenue requirements for customers will be smoothed out, and the Company can recover its reasonable and necessary maintenance costs for serving customers, albeit after-the-fact. The Company is not requesting carrying costs on this regulatory asset or inclusion of the costs in rate base, just deferred recovery of the expenses over time.

Q. DID THE COMPANY INCLUDE ANY FORECASTED AMORTIZATION EXPENSE IN ITS COST OF SERVICE AND PROPOSED BASE RATES FOR THIS REQUESTED REGULATORY TREATMENT?

A. Yes. The proposed base rates include a forecasted amount of amortization ($6,629,000) for this Edwardsport major planned outage normalization reserve.

Q. BECAUSE BASE RATES WILL INCLUDE A DEFERRAL FOR THE AFOREMENTIONED EDWARDSPORT MAJOR PLANNED OUTAGE USING A SEVEN-YEAR RECOVERY PERIOD, WHAT WILL HAPPEN

IF THE NEXT MAJOR PLANNED OUTAGE OCCURS LATER THAN THE CURRENTLY PLANNED SEVEN-YEAR CYCLE?

A. If the next outage is delayed, the Company would continue to collect the amortization amount included in base rates, rather than adjust rates downward when the 2020 outage costs in the normalization reserve are fully amortized. The costs would be included in a regulatory liability and offset with the costs when the next major planned outage does occur. At the time of the next base rate case, the net balance in the regulatory asset or liability account would be factored into base rates, along with current levels of costs.

Q. WHAT WILL HAPPEN IF THE NEXT MAJOR PLANNED OUTAGE OCCURS EARLIER THAN THE CURRENTLY PLANNED SEVEN-YEAR CYCLE?

A. In that case, the Company would continue to collect the amortization amount included in base rates until the next base rate case and would defer the incremental costs of the next major planned outage into the normalization reserve regulatory asset account. At the time of the next base rate case, the balance in the regulatory asset account would be factored into base rates, along with current levels of costs.

Q. WHY IS THIS REQUESTED ACCOUNTING AND RATEMAKING TREATMENT REASONABLE?

A. The required planned maintenance schedule and costs at Edwardsport are variable, with a major, costlier planned outage required approximately every seven years, and the first major planned outage is in the Test Period. The Company's proposal provides a balanced way to afford the Company the opportunity to recover the reasonable and necessary costs of the 2020 major planned outage, while avoiding customer rate volatility by recovering the costs over time and protecting customers if the actual incremental major planned outage costs incurred are less than forecasted.

D. Pension Settlement Accounting

Q. WHAT ACCOUNTING TREATMENT IS THE COMPANY REQUESTING RELATED TO PENSION SETTLEMENT ACCOUNTING?

A. As explained in the testimony of Duke Energy Indiana witness Mr. Jeffrey R. Setser, pension settlement accounting, which is prescribed by U.S.GAAP accounting in certain situations, results in an acceleration of recognition of the settled portion of gains or losses currently deferred in a pension regulatory asset on the Company's accounting books. Absent triggering settlement accounting, these gains or losses would be amortized as a portion of net periodic pension cost over the average remaining service period of active participants. However, if all or most of a plan's participants are inactive, the average remaining life expectancy of the inactive participants is used instead of average remaining service period.

If settlement accounting is triggered for regulated entities, the losses on the settled portion of the net periodic pension obligation must be reflected as an expense immediately, unless it is probable the costs (the amortization of which are currently a portion of pension cost being recovered through rates) will be recovered from customers. In this case, the Company would propose that the settled portion of the losses be moved to a separate regulatory asset account and continue to be amortized over the average remaining service period of the pension plan participants. This is the treatment the Company is requesting Commission authority for, both for the settlement accounting triggered in 2019, as well as for any future settlement accounting triggered.

Q. WHY IS THIS REQUESTED PENSION SETTLEMENT ACCOUNTING TREATMENT REASONABLE?

A. This GAAP required settlement accounting does not increase pension cost to the Company or to customers – it just accelerates the recognition of it on the Company's accounting books, reducing the original cost in the pension asset and future benefit costs from the actuarial study. The Company's requested accounting treatment would merely re-establish the costs in a separate regulatory asset and continue to amortize the costs over the same or similar remaining lives of the pension participants. Annual pension costs would remain basically the same. Without the Commission's approval of this accounting treatment, the Company would incur earnings erosion and volatility, rather than the smoothing of these reasonable and necessary pension costs over time that normal pension accounting treatment affords.

E. <u>Requested Accounting Treatment</u>

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY FOR THE REMAINING NET BOOK VALUE OF WABASH RIVER UNIT 6, COAL ASH REMEDIATION AND CLOSURE COSTS, EDWARDSPORT MAJOR PLANNED OUTAGE NORMALIZATION RESERVE, AND PENSION SETTLEMENT ACCOUNTING COSTS 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 of the retail jurisdictional portion of the remaining book value of Wabash River and inclusion in rate base for recovery via base rates; deferral and recovery in current or future rates of the incurred and to-be-incurred coal ash remediation and closure costs, with carrying costs until included in rate base in current or future rates; deferral of the 2020 major planned outage costs at Edwardsport for a major planned outage normalization reserve, with recovery over seven years in current rates; and deferral in a new regulatory asset of the pension settlement costs incurred or to be incurred with amortization over the life of pension plan participants, until they can be included in retail 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 addition, Indiana Code 8-1-8.4 specifically provides for the timely recovery of both direct and indirect costs, including financing costs, associated with the federally mandated coal ash compliance projects. Both post-in-service carrying costs and carrying costs on the costs to be deferred until the next rate case are financing costs associated with the federally mandated projects.

For the Company to defer these various costs or to continue to defer them as a regulatory asset in the case of Wabash River Unit 6, coal ash expenditures, and pension costs triggered by settlement accounting, it must be probable that such costs will be recovered through rates in future periods. 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.

X. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS 4-D (DLD) THROUGH 4-W (DLD) PREPARED UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Indiana, LLC
Summary of 2020 Projected Revenue and Pro Forma Adjustments
(Thousands of Dollars)

			Pro Forma Adjustments								
Line No.	Description	2020 Forecast	Remove Revenues Staying in Riders	Remove Change in Unbilled Revenues	Remove Non-Native Sales Revenue	Remove Short-term Bundled Non-Native Sale	Remove MISO RECB/MVP Revenues	Update Miscellaneous Charge Amounts	Total Pro Forma Adjustments	Adjusted Amount	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
	Retail Revenue										
1	Residential	$ 1,032,138	$ (19,435)	$ (25,109)	$ -	$ -	$ -	$ -	$ (44,544)	$ 987,594	1
2	Commercial	711,222	(6,182)	(3,515)	-	-	-	-	(9,697)	701,525	2
3	Industrial	818,105	(3,922)	(45)	-	-	-	-	(3,967)	814,138	3
4	Other Public Authorities	14,406	(67)	(184)	-	-	-	-	(251)	14,155	4
5	Street Lighting	557	(18)	-	-	-	-	-	(18)	539	
6	**Total Retail Revenues**	**$ 2,576,428**	**$ (29,624)**	**$ (28,853)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (58,477)**	**$ 2,517,951**	6
7	Wholesale Sales	252,011	-	-	(34,717)	(23,976)	-	-	(58,693)	193,318	7
	Other Revenues										
8	Production Related	39,916	-	-	-	-	-	-	-	39,916	8
9	Transmission Related	27,893	-	-	-	-	(3,369)	-	(3,369)	24,524	9
10	Distribution Related	10,057	-	-	-	-	-	(928)	(928)	9,129	10
11	Administrative and General Related	10,352	-	-	-	-	-	266	266	10,618	11
12	Steam Sale Revenues	6,000	-	-	-	-	-	-	-	6,000	12
13	**Total Other Revenues**	94,218	-	-	-	-	(3,369)	(662)	(4,031)	90,187	13
14	**Total Revenue from Electric Sales**	**$ 2,922,657**	**$ (29,624)**	**$ (28,853)**	**$ (34,717)**	**$ (23,976)**	**$ (3,369)**	**$ (662)**	**$ (121,201)**	**$ 2,801,456**	14
	Refences:	WP REV1-DLD WP REV4-DLD	Schedule REV2	Schedule REV3	Schedule REV4	Schedule REV5	Schedule REV6	Schedule REV7			

Summary of Exhibits and Supporting Workpapers
for Witness Diana L. Douglas

Line No	Exhibit Number	Exhibit Also Included with MSFR Filing?	Schedule Number	Exhibit/Schedule Description (Refers to 2020 Test Period Unless Noted)	Work Paper Reference Number(s)	Workpaper Included with MSFR Filing?	IAC 170 MSFR Reference Number	Line No
1	Exhibit 4-A (DLD)	✓	N/A	Historical Reference Period (2018) Comparative Balance Sheet	N/A		1-5-6(1)(A)	1
2	Exhibit 4-B (DLD)	✓	N/A	Historical Reference Period (2018) Cash Flow Statement	N/A		1-5-6(1)(B)	2
3	Exhibit 4-C (DLD)	✓	N/A	Historical Reference Period (2018) Comparative Income Statement	N/A		1-5-6(1)(C)	3
4	Exhibit 4-D (DLD)	✓	RR1	Test Period Revenue Requirement Calculation	N/A		1-5-6(2)	4
5	Exhibit 4-E (DLD)	✓	OPIN1	Jurisdictional Test Period Electric Operating Income	OPIN1-DLD	✓	Sch: 1-5-6(3) WP: 1-5-8(a)(1)	5
6			OPIN2	Proposed Revenue and Operating Expense Increment			1-5-8(a)(2)	6
7			OPIN3	Total Company Test Period Electric Operating Income			1-5-8(a)(2)	7
8			OPIN4	Summary of Pro Forma Adjustments to Electric Operating Income Before Income Taxes			1-5-8(a)(2)	8
9			REVISED REV1	Summary of Pro Forma Adjustments to Revenues	REVISED REV1-DLD - REVISED REV3-DLD, REV4-DLD	✓	1-5-8(a)(2)	9
10			OM1	Test Period O&M Expense by Account (Excluding Fuel, EA and Purchased Power)			1-5-8(a)(2)	10
11			OM2	Summary of Pro Forma Adjustments to O&M (Excluding Fuel, EA and Purchased Power)			1-5-8(a)(2)	11
12			OM15	Remove Other Post Retirement Benefits Expense	OM1-DLD	✓	1-5-8(a)(2)	12
13			N/A	Grantor Trust 12/31/18 Balance	1-DLD			
14			OM16	Normalize Edwardsport Outage O&M Costs	OM2-DLD	✓	1-5-8(a)(2)	14
15			DA1	Summary of Pro Forma Adjustments to Depreciation and Amortization Expense				15
16			DA3	Adjust and Annualize Production Plant Depreciation Expense	RB7-DLD, RB8-DLD, RB9-DLD	✓	Sch: 1-5-8(a)(2) WP: 1-5-8(a)(2)	16
17			DA4	Adjust and Annualize Transmission Plant Depreciation Expense	RB10-DLD, RB11-DLD, RB12-DLD	✓	Sch: 1-5-8(a)(2) WP: 1-5-8(a)(2)	17
18			DA5	Adjust and Annualize Distribution Plant Depreciation Expense	RB13-DLD, RB14-DLD, RB15-DLD	✓	Sch: 1-5-8(a)(2) WP: 1-5-8(a)(2)	18
19			DA6	Adjust and Annualize General Plant Depreciation Expense	RB16-DLD, RB17-DLD, RB18-DLD	✓	Sch: 1-5-8(a)(2) WP: 1-5-8(a)(2)	19
20			DA7	Adjust and Annualize Intangible Plant Depreciation Expense	RB19-DLD, RB20-DLD, RB21-DLD	✓	Sch: 1-5-8(a)(2) WP: 1-5-8(a)(2)	20
21			DA8	Remove General Depreciation Costs Reimbursed by MISO for RECB/MVP Projects				21
22			DA9	Summary of Pro Forma Adjustments to Regulatory Asset Amortization Expense				22
23			DA10	Adjust and Annualize Regulatory Asset Amortization Expense by Function	DA1-DLD - DA4-DLD	✓	1-5-8(a)(2)	23
24			OTX1	Summary of Pro Forma Adjustments to Taxes Other Than Income Taxes				24
25			OTX5	Annualize Property Tax Expense	OTX1-DLD-OTX3-DLD	✓	1-5-8(a)(2)	25
26	Exhibit 4-F (DLD)	✓	RB1	Summary of Total Company and Jurisdictional Rate Base	RB5-DLD, RB22-DLD	✓	Sch:1-5-6(4) WP:1-5-9(a)(1)	26
27			RB2	Pro Forma Adjustments to Net Utility Plant	RB1-DLD, RB6- DLD - RB21-DLD, RB24-DLD	✓	Sch:1-5-6(4) WP:1-5-9(a)(1)	27
28			RB4	Pro Forma Adjustments to Regulatory Assets Included in Rate Base	RB2-DLD, RB3-DLD, RB23-DLD, RB25-DLD	✓	Sch:1-5-6(4) WP:1-5-9(a)(1)	28
29			RB5	Pro Forma Adjustment to Materials and Supplies Inventory	RB4-DLD	✓	Sch:1-5-6(4) WP:1-5-9(a)(1)	29
30			RB6	Summary of Fair Value Rate Base				30
31	Exhibit 4-G (DLD)	✓	CS1	Capital Structure and Cost of Capital for Historical Reference Period (2018)	CS6-DLD	✓	1-5-6(5)	31
32			CS2	Embedded Cost of Long Term Debt for Historical Reference Period (2018)	CS1-DLD - CS5-DLD	✓	1-5-6(5)	32
33			CS3	Capital Structure and Cost of Capital for Test Period	CS12-DLD	✓	1-5-6(5)	33
34			CS4	Embedded Cost of Long Term Debt for Test Period	CS7-DLD - CS11-DLD	✓	1-5-6(5)	34

Summary of Exhibits and Supporting Workpapers
for Witness Diana L. Douglas

Line No	Exhibit Number	Exhibit Also Included with MSFR Filing?	Schedule Number	Exhibit/Schedule Description (Refers to 2020 Test Period Unless Noted)	Work Paper Reference Number(s)	Workpaper Included with MSFR Filing?	IAC 170 MSFR Reference Number	Line No
35	Exhibit 4-H (DLD)	✓		Effective Income Tax Rate for Historical Reference Period (2018) and for Test Period			1-5-6(5)	35
36			TX1	Summary of Total Company and Jurisdictional Test Period Income Taxes			1-5-6(5)	36
37			TX2	Pro Forma Adjustment to Computation of Current Federal and State Income Taxes	TX3-DLD	✓	1-5-6(5)	37
38			TX3	Determination of Synchronized Interest for Income Tax Calculation			1-5-6(5)	38
39			TX4	Determination of Parent ("Muncie Remand") Interest for Income Tax Calculation	TX8-DLD, TX9-DLD	✓	1-5-6(5)	39
40			TX5	Pro Forma Adjustment to IGCC State Investment Tax Credit Taken for Income Taxes			1-5-6(5)	40
41			TX6	Pro Forma Adjustment to Computation of Deferred Federal and State Income Taxes	TX1-DLD, TX2-DLD, TX4-DLD, TX5-DLD, TX7-DLD	✓	1-5-6(5)	41
42			TX7	Pro Forma Adjustment to Federal Investment Tax Credit	TX6-DLD	✓	1-5-6(5)	42
43	Exhibit 4-I (DLD)		RA1	Step 1 Revenue Adjustment Rate Calculation	N/A			43
44			RA2	Step 1 Revenue Requirement Calculation for Step 1 Revenue Adjustment	N/A			44
45	Exhibit 4-J (DLD)		OPIN1	Step 1 Jurisdictional Electric Operating Income	N/A			45
46			OPIN2	Step 1 Proposed Revenue and Operating Expense Increment	N/A			46
47			OPIN3	Step 1 Total Company Electric Operating Income	N/A			47
48			DA1	Step 1 Summary of Pro Forma Adjustments to Depreciation and Amortization Expense	N/A			48
49			DA3	Adjust and Annualize Production Plant Depreciation Expense for Step 1	N/A			49
50			DA4	Adjust and Annualize Transmission Plant Depreciation Expense for Step 1	N/A			50
51			DA5	Adjust and Annualize Distribution Plant Depreciation Expense for Step 1	N/A			51
52			DA6	Adjust and Annualize General Plant Depreciation Expense for Step 1	N/A			52
53			DA7	Adjust and Annualize Intangible Plant Depreciation Expense for Step 1	N/A			53
54			DA8	Remove General Depreciation Costs Reimbursed by MISO for RECB/MVP Projects	N/A			54
55	Exhibit 4-K (DLD)		RB1	Step 1 Summary of Total Company and Jurisdictional Rate Base (2019)	N/A			55
56			RB2	Step 1 Pro Forma Adjustments to Net Utility Plant	N/A			56
57			RB4	Step 1 Pro Forma Adjustments to Regulatory Assets Included in Rate Base	N/A			57
58			RB5	Step 1 Pro Forma Adjustment to Materials and Supplies Inventory	N/A			58
59	Exhibit 4-L (DLD)		CS1	Step 1 Capital Structure and Cost of Capital (2019)	CS18-DLD			59
60			CS2	Step 1 Embedded Cost of Long Term Debt (2019)	CS13-DLD - CS17-DLD			60
61	Exhibit 4-M (DLD)		N/A	Rider 65 TDSIC Clean Tariff	N/A			61
62	Exhibit 4-N (DLD)		N/A	Rider 65 TDSIC Red-line Tariff	N/A			62
63	Exhibit 4-O (DLD)		N/A	Rider 66 EE with RDM Clean Tariff	N/A			63
64	Exhibit 4-P (DLD)		N/A	Rider 66 EE with RDM Red-line Tariff	N/A			64
65	Exhibit 4-Q (DLD)		N/A	Rider 66 EE without RDM Clean Tariff	N/A			65
66	Exhibit 4-R (DLD)		N/A	Rider 66 EE without RDM Red-line Tariff	N/A			66
67	Exhibit 4-S (DLD)		N/A	Rider 67 Credits Clean Tariff	N/A			67
68	Exhibit 4-T (DLD)		N/A	Rider 67 Credits Red-line Tariff	N/A			68
69	Exhibit 4-U (DLD)		N/A	Appendix A - Listing of Riders Clean Tariff	N/A			69

Summary of Exhibits and Supporting Workpapers
for Witness Diana L. Douglas

Line No	Exhibit Number	Exhibit Also Included with MSFR Filing?	Schedule Number	Exhibit/Schedule Description (Refers to 2020 Test Period Unless Noted)	Work Paper Reference Number(s)	Workpaper Included with MSFR Filing?	IAC 170 MSFR Reference Number	Line No
70	Exhibit 4-V (DLD)		N/A	Appendix A - Listing of Riders Red-line Tariff	N/A			70
71	Exhibit 4-W (DLD)		N/A	Summary of Exhibits and Supporting Workpapers	N/A			71
	Additional Workpapers:							
72				Grantor Trust Asset Valuation	WP 1-DLD			72
73				Rider Revenues After the Rate Case	SUPPLEMENTAL WP REV5-DLD			73

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: Diana L. Douglas
Diana L. Douglas

Dated: 9/9/19