Cause No. 46038

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF SUZANNE E. SIEFERMAN

Petitioner's Exhibit 4

April 4, 2024

DIRECT TESTIMONY OF SUZANNE E. SIEFERMAN, DIRECTOR, RATES AND REGULATORY PLANNING ON BEHALF OF DUKE ENERGY INDIANA, LLC BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman, 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.

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

A. I am responsible for the preparation of financial and accounting data used in Company rate filings and petitions for changes in various tracking mechanisms.

Q. PLEASE STATE 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. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society. Since my employment with the Company in 1990, I have held various financial and accounting positions supporting the Company and its affiliates. Prior to my move to the Rates and Regulatory Planning department in 2008, I held positions in Benefits Accounting, Corporate Accounting, Business Unit Financial Reporting and External Reporting groups.

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 compliance with, and organization of, the Minimum Standard Filing Requirements ("MSFR");

2) Discuss the Capital Structure included in the filing;

3) Sponsor and support certain revenue and expense *pro forma* adjustments applicable to the Forward-Looking Test Period and a related portion of the Revenue Requirements model;

4) Explain and support proposed changes to certain of the Company's existing trackers to be effective with the implementation of the Company's revised base rates; and

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

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

A. I am sponsoring the following *pro forma* adjustments applicable to the Forward-Looking Test Period. Support for these can be found in Exhibit 26, Attachment 26-C and are summarized below:

Table 1:

Attachment	*Pro Forma* Adjustments
Attachment 26-C	Schedule REV1 – Summary of Revenue Schedule REV2 – Remove Revenues Staying in Trackers Schedule REV3 – Remove Non-Jurisdictional Revenues Special Contract 1-B Schedule REV4 – Remove Non-Jurisdictional, Non-Ongoing, and Transmission Revenues for Special Contract 4 Schedule REV5 – Remove Revenues for Expiring Wholesale Contracts Schedule REV6 – Remove Non-Native Sales Revenue Schedule REV7 – Remove Short-term Bundled Non-Native Sales Revenue Schedule REV8 – Remove Revenues for RECB/MVP Projects
Schedule 26-C	Schedule COGS1 – Summary of Cost of Goods Sold Schedule COGS2 – Remove Fuel Expense Associated with Short-term Bundled Non-Native Sales

Attachment	***Pro Forma* Adjustments**
	Schedule COGS3 – Remove Fuel Expense Associated with Non-Native Sales Schedule COGS4 – Remove Non-Jurisdictional Fuel Expense for Special Contract 1-B Schedule COGS5 – Remove Non-Ongoing Fuel Expense for Special Contract 4 Schedule COGS6 – Remove Fuel Expense for Expiring Wholesale Contracts Schedule COGS7 – Remove Fuel Deferral
Schedule 26-C	Schedule OM3 – Remove RECB/MVP O&M Expenses Schedule OM4 –Remove Energy Efficiency O&M Staying in Tracker Schedule OM5 – Remove TDSIC O&M Staying in Tracker Schedule OM6 – Remove Public Utility Fee Staying in Trackers Schedule OM7 – Remove O&M Tracker Deferrals Schedule OM10 – Remove OPRB O&M Expense Schedule OM13 – Normalize Major Storm O&M Expenses Schedule OTX1 – Summary Schedule OTX2 – Remove IGCC Property Tax Staying in Tracker Schedule OTX3 – Remove TDSIC Related Property Tax Deferrals Staying in Tracker

Attachment	***Pro Forma* Adjustments**
	Schedule OTX5 – Remove RECB/MVP Payroll Tax Expense Schedule OTX6 – Remove Payroll Taxes Associated with Energy Efficiency ("EE") Staying in the Tracker Schedule OTX7 – Remove Payroll Taxes Associated with TDSIC Staying in the Tracker Schedule OTX8 – Normalize Major Storm Payroll Taxes

The Company's remaining operating income *pro forma* adjustments are sponsored by Company witnesses Ms. Graft, Ms. Lilly, and Mr. Flick II.

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

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

- Tracker No. 68 – Regional Transmission Operator Non-Fuel Costs and Revenue Adjustment ("Tracker 68" or "RTO Tracker");
- Tracker No. 70 – Reliability Adjustment ("Tracker 70" or "Reliability Tracker"); and
- Tracker No. 73 – Renewable Energy Project Adjustment ("Tracker 73" or "Renewables Tracker").

Copies of the red-lined and clean revised tariff sheets for Tracker 68, Tracker 70, and Tracker 73 are attached to my testimony as Attachments 4-A (SES) through 4-F (SES).

Q. WHAT REQUESTS FOR NEW OR CONTINUED DEFERRAL AUTHORITY AND RATE RECOVERY WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I support the Company's request for continuation of a storm normalization reserve account to be used for amounts over and under the amount of storm restoration costs included in base rates.

Q. DO YOU HAVE ANY OTHER ITEMS YOU PLAN TO ADDRESS?

A. Yes. I will also discuss the following:

- Proposed change associated with the Company's *GoGreen* program.
- Update on status of electric vehicle ("EV") Fast Charging stations and proposed ratemaking for assets and net revenues.
- Proposal to refund surplus funds accumulated in the Grantor Trust, which is used to cover Other Post Retirement Benefits ("OPRB") costs.

Q. ARE YOU SPONSORING ANY WORKPAPERS TO SUPPORT ATTACHMENTS?

A. Yes. I will be sponsoring workpapers for my Attachments. See the Index to Petitioner's Exhibit 26, which shows a list of sponsored workpapers.

II. MINIMUM STANDARD FILING REQUIREMENTS

Q. PLEASE EXPLAIN HOW DUKE ENERGY INDIANA HAS COMPLIED WITH THE COMMISSION'S GENERAL ADMINISTRATIVE ORDER ON RATE CASES (GAO 2013-5) AND THE COMMISSION'S MINIMUM STANDARD FILING REQUIREMENTS ("MSFRs").

A. As the Petition initiating this case indicates, Duke Energy Indiana submitted a Notice of Intent on March 5, 2024, at least 30 days prior to the date of filing for a change in base rates, and Duke Energy Indiana has discussed this filing with the Indiana Office of Utility Consumer Counselor ("OUCC") and other stakeholders. As the GAO states, the MSFRs contemplate a historical test period, and thus the documentation requirements do not perfectly fit with a forward-looking test period. Accordingly, the Company used the MSFRs as guidance as to the categories of information to include in its case in chief and supporting documentation. Duke Energy Indiana's filing includes the following:

- A case-in-chief that includes a complete description of the rate relief requested, along with supporting workpapers.
- Documentation supporting the Forward-Looking Test Period, including calculations, assumptions, and results. In addition, Duke Energy Indiana has provided responses to the MSFRs for the Forward-Looking Test Period and, where appropriate, for the Base Period.
- A summary of the differences from the historic base period to the Forward-Looking Test Period presented by Company witness Mr. Rutledge, and supported by various Company witnesses in the generation, transmission, distribution, customer, and administrative and general functional areas.
- Testimony, exhibits, and/or MSFRs that include:

- Jurisdictional operating revenues and expenses, including taxes and depreciation;
- Balance sheet and income statements for the forecasted Forward-Looking Test Period, the Base Year, and the 12 months in between the Forward-Looking Test Period and the Base Year, as available;
- Jurisdictional rate base as of the end of the Forward-Looking Test Period;
- Proposed cost of capital and capital structure;
- Jurisdictional class cost of service study; and
- Proposed rate design and *pro forma* tariff sheets.

Q. DOES THE COMPANY'S FILING DEVIATE IN ANY WAY FROM THE MSFRS OR GAO 2013-5?

A. As contemplated by GAO 2013-5, Duke Energy Indiana followed the Commission's guidance, but deviated from the guidance when appropriate in light of the use of a Forward-Looking Test Period. More specifically, Duke Energy Indiana made the following deviations from the MSFRs and GAO guidance:

- The Base Period reflects actual revenues, expenses and rate base for the twelve months ended August 31, 2023. This Base Period does not mirror the Forward-Looking Test Period due to timing of the data available when the Company was able to file the case. The Forward-Looking Test Period is the calendar year 2025. At the time this case was being assembled, the calendar year 2023 had not yet closed and was therefore not available, and the calendar year 2022 would have been too stale to use as a Base Period.
- Duke Energy Indiana has provided detailed "supporting documentation" and "supporting calculations" for the Forward-Looking Test Period. However, we have not provided this supporting documentation in the form of "individual adjustments" from the Base Period to the Forward-Looking Test Period under GAO 2013-5 ¶ II.A.2.c. See the testimony of Company

witness Mr. Rutledge for the explanation of the Company's forecasting process and for a summary of differences between the Forward-Looking Test Period and the Base Period.

- Because of the Two-Step rate increase, it was not necessary to use an average monthly rate base under GAO 2013-5 ¶ II.A.6.b.
- Regarding revision to the Company's retail electric tariff, which can be found in Company witness Mr. Flick's Attachment 7-B (RAF), Duke Energy Indiana has used computer redlining, as opposed to using bold type as referenced in the MSFRs. Due to formatting issues, only the substantive changes in the tariff are noted in redline in some cases.

Q. PLEASE EXPLAIN THE ORGANIZATION OF THE MSFRS.

A. Concurrent with its case-in-chief testimony filing, the Company has submitted files containing the MSFR requirements, numbered according to the Indiana Administrative Code citations. Where certain MSFRs are included in the case-in-chief testimony, the MSFR files cross-reference to the appropriate witness' testimony, Attachments, or Workpapers. As more fully described in the testimony of Company witness Ms. Graft, the basic accounting exhibits required to be filed with the case-in-chief for MSFR 170 IAC 1-5-6 can be found in Petitioner's Exhibit 26. Finally, those MSFRs and attachments requiring confidential treatment will be supported with a Motion for Confidentiality and provided to the Commission upon Commission preliminary approval of confidential treatment. They will be supplied to the OUCC and non-competitive intervenors upon execution of a mutually agreeable non-disclosure agreement.

III. CAPITAL STRUCTURE AND COST OF CAPITAL

Q. PLEASE EXPLAIN THE CS SCHEDULES OF PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule CS1 presents Duke Energy Indiana's Capital Structure and Cost of Capital for the Forward-Looking Test Period and Schedule CS4 presents Duke Energy Indiana's Capital Structure and Cost of Capital for the Base Period. Schedules CS2 and CS3 (for Forward-Looking Test Period) and CS5 and CS6 (for Base Period) support the cost of capital calculation and are discussed in more detail later in this section. Both sets of Schedules are in the same format, calculated using the same expanded regulatory presentation and the same methodology as has been used in recent years for the Company's last base rate case in Cause No. 45253, and all the Company's trackers 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 tracker filings. The forecasted financial capital structure, provided by Company witness Mr. Rutledge and supported by Company witness Mr. Bauer, 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 cost rates for investment tax credits ("ITC") and zero cost of capital for accumulated deferred income taxes). As shown in the General Terms and Conditions sponsored by Company witness Mr. Flick, the Company is proposing the Commission approve the Company's request to allow it to use a 5% interest rate on customer deposits eligible for interest accrual for the Forward-Looking Test Period, rather than the 2% currently effective rate, to better reflect the current interest rate environment. The rate of return on equity is the existing approved 9.7% for the Base Period and the proposed 10.5%, supported by the testimony of Company witnesses Messrs. McKenzie and Pinegar. The testimony of Company witness Mr. Bauer 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 Association, Inc. d/b/a 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 Center Point Energy Indiana South ("CenterPoint"), to provide gas to the Edwardsport IGCC plant via a gas pipeline which CenterPoint 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. (Rate Base was also adjusted to remove the corresponding Gas Pipeline Lease asset on Exhibit 26, Attachment 26-C Schedule RB2, which is supported by Company witness Ms. Lilly).

Q. WAS SHORT-TERM DEBT INCLUDED IN THE REGULATORY CAPITAL STRUCTURE?

A. No. Short-term debt has been excluded from the capital structure consistent with previous Commission Orders, including the Company's last base rate case in Cause No. 45253. However, consistent with the Company's recent practice, it has included a $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, and which is classified as long-term debt on the Company's financial statements. The Company has been reflecting this debt as part of long-term debt in its capital structure and cost of capital for all capital tracker filings beginning in 2008 and in the last base rate case.

Q. DOES THE ACCUMULATED DEFERRED INCOME TAX BALANCE USED AS A ZERO COST SOURCE OF CAPITAL IN THE DETERMINATION OF THE WEIGHTED AVERAGE COST OF CAPITAL INCLUDE AMOUNTS FOR EXCESS DEFERRED INCOME TAXES ("EDIT")?

A. Yes. The Company has adjusted the amount of deferred income taxes included in the Capital Structure to include 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 as an additional zero cost source of capital component in the calculation.

Q. HAVE OTHER ADJUSTMENTS BEEN MADE TO THE COMPANY'S ACCUMULATED DEFERRED INCOME TAXES TO DETERMINE THE AMOUNT YOU INCLUDED IN THE REGULATORY CAPITAL STRUCTURE?

A. Yes. 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 also removed the accumulated deferred income tax balances associated with the non-jurisdictional RUS debt, which was removed from the capital structure, as well as with the Company's former manufactured gas plant ("MGP") sites. As first approved by the Commission in Cause No. 43114 IGCC-4S1 Order, the Company has also 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. The Company has also included an adjustment to remove the deferred income tax asset balances related to the Company's deferred utilization of ITCs. Similar adjustments were made in developing the cost of capital approved by the Commission in the Company's last base rate case in Cause No. 45253. Schedules CS3 and CS6, which support the deferred accumulated income tax balance included in the capital structure, detail these deferred income tax adjustments.

Q. WHAT RATE OF RETURN IS THE COMPANY REQUESTING?

A. As shown on Exhibit 26, Attachment 26-C Schedule CS1, the Company is requesting an authorized rate of return (weighted average cost of capital) of 6.52%. The recent rate of return for the Base Period, as shown on Schedule CS4, is 5.90%.

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

A. As shown on Petitioner's Exhibit 26, Attachment 26-C Schedule CS2, the weighted average cost rate applicable to the Company's long-term debt for the Forward-Looking Test Period is 4.87%. As shown on Schedule CS5, the weighted average cost rate applicable to the Company's long-term debt for the Base Period is 4.83%.

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 investable 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.

Q. DID YOU PROVIDE THE FORECASTED JUNE 30, 2024 CAPITAL STRUCTURE AND COST OF CAPITAL INFORMATION TO MS. GRAFT FOR USE WITH THE STEP 1 CALCULATION?

A. Yes. As discussed in the testimony of Company witness Ms. Graft, the Company will be implementing new base rates, upon Commission approval, via a two-step process. Exhibit 26, Attachment 26-C, Schedules RA18 and RA19 are the forecasted Capital Structure and Cost of Capital schedules, respectively, for June 30, 2024. This information has been used, in conjunction with forecasted used and useful net plant in-service at June 30, 2024, to estimate the Step 1 adjustments. Please refer to the direct testimony of Company witness Ms. Graft for a detailed discussion regarding Step 1 and Step 2 base rate implementation.

IV. OPERATING INCOME *PRO FORMA* ADJUSTMENTS AND ACCOUNTING ATTACHMENTS

Q. WHERE CAN THE *PRO FORMA* ADJUSTMENTS BE FOUND IN THE FILING?

A. As more fully described in the testimony of Company witness Ms. Graft, Petitioner's Exhibit 26 is an Excel file comprised of the majority of the basic accounting exhibits required to be filed with the case-in-chief by the MSFRs pursuant to 170 IAC 1-5-6. Included within Petitioner's Exhibit 26 are several attachments supporting the individual requirements. The Revenue Requirements and associated *Pro Forma* Adjustments can be found in Exhibit 26, Attachment 26-C with the applicable witness listed at the top of each schedule. There are separate Schedules within Revenue Requirements for such items as Revenues, Cost of Goods Sold, O&M, and Other Taxes.

A. <u>Revenues</u>

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV1.

A. Schedule REV1 summarizes the *pro forma* adjustments made to Revenues on Schedules REV2 through REV9. I sponsor and discuss Schedules REV2 through REV8 in my testimony and Company witness Mr. Flick sponsors Schedule REV9.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV2 – REMOVE TRACKER REVENUES FOR COSTS/CREDITS THAT WILL REMAIN IN TRACKERS.

A. Schedule REV2 removes $17,281,000 from Forward-Looking Test Period revenues for revenues associated with costs and/or credits that will be recovered via trackers rather than base rates under the Company's rate proposal. I discuss the costs and/or credits the Company is proposing to recover via Trackers 68, 70, and 73 in more detail later in my testimony. Company witness Ms. Graft discusses the costs and/or credits the Company is proposing to recover via Tracker No. 60 – Fuel Cost Adjustment. Company witness Ms. Lilly discusses the costs and/or credits the Company is proposing to recover via the remaining trackers in her testimony.

Revenues associated with costs and/or credits that will be recovered via trackers should be excluded from the development of new base rates. Workpapers REV1 and REV6 support the calculation of this *pro forma* adjustment.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV3 – WHICH REMOVES ALL NON-TRANSMISSION REVENUES RELATED TO SPECIAL CONTRACT 1-B.

A. Schedule REV3 removes $13,488,000 of demand and administrative fee revenues associated with Special Contract 1-B from retail revenues as these amounts should be considered non-jurisdictional and thus retained by the Company. In addition, $74,772,000 is being removed for the remaining forecasted non-transmission revenues above the firm level as these are considered a "pass through." These amounts are expected to be equal to the costs incurred to serve this load with purchases from either the Midcontinent Independent System Operator, Inc. ("MISO") or designated Power Purchase Agreements ("PPAs"), or a combination of both. Given that the Company generation will not be used to serve this load, there is no impact to native customers and therefore these amounts are being removed from the revenue requirements. See testimonies of Company witnesses Mr. Swez and Ms. Diaz for further information regarding Special Contract 1-B.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV4 – WHICH REMOVES NON-JURISDICTIONAL, NON-ONGOING, AND TRANSMISSION REVENUES RELATED TO SPECIAL CONTRACT 4.

A. Schedule REV4 removes a total of $2,438,000 of revenues associated with Special Contract 4 from retail revenues. Of this amount, $462,000 is for demand revenues which the Company has requested be treated as non-jurisdictional; $1,581,000 of this amount is for non-ongoing amounts forecasted for the construction period; and $395,000 is for transmission revenues which the Company has proposed will be credited to customers through the TDSIC tracker. See the testimony of Company witness Ms. Diaz for further information regarding the rationale for these adjustments.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV5 – WHICH REMOVES WHOLESALE REVENUES FOR EXPIRING CONTRACTS.

A. Schedule REV5 reflects a reduction to wholesale revenues in the amount of $50,470,000 for two wholesale contracts that are expiring at the end of 2025. These revenues have been removed from the forecast for purposes of developing new base rates. See testimony of Company witness Ms. Diaz for a discussion on how the Company is reflecting the expiration of these wholesale contracts in its cost-of-service ("COSS") model. Also, see the testimony of Company witness Ms. Lilly, who discusses how the Company plans to credit customers through Tracker No. 67 with the base rate impact of the revenues received under these contracts between the time new base rates go into effect and when the contracts expire at the end of 2025, which was calculated by Ms. Diaz.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV6 - REMOVE REVENUES FOR NON-NATIVE WHOLESALE SALES.

A. Schedule REV6 removes $6,460,000 from Forward-Looking Test Period revenues associated with traditional non-native sales to reflect that these revenues are included in the off-system sales sharing mechanism of Tracker 70. The Company is proposing in this case to continue sharing net positive non-native sales margins 100% with customers through the annual tracking mechanism. See discussion on this topic later in my testimony in Section V as well as the Direct Testimony of Company witness Mr. Swez.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV7 - REMOVE REVENUES ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule REV7 removes $20,087,000 from Forward-Looking Test Period revenues for a short-term bundled non-native contract. See discussion later in my testimony regarding proposal for changes to Tracker 70 as well as the Direct

Testimony of Company witness Mr. Swez.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE REV8 - REMOVE REVENUES FOR RECB/MVP PROJECTS.

A. Schedule REV8 removes $4,400,000 from Forward-Looking Test Period revenues associated with certain of the Company's transmission projects recovered via MISO. The Company 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 reimburses the Company for the cost of these projects by charging all MISO transmission owners for the cost of the expansion projects through Schedule 26 and charging all market participants through Schedule 26A. As such, the Company excludes the revenues received and costs incurred associated with these projects from its retail ratemaking.

B. Cost of Goods Sold

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS1.

A. Schedule COGS1 summarizes the *pro forma* adjustments made to Cost of Goods Sold on Schedules COGS2 through COGS7. I sponsor and discuss Schedules COGS2 through COGS7. Company witness Ms. Graft sponsors Schedule COGS8, which is a calculation of the new Base Cost of Fuel being proposed.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS2 – REMOVE FUEL EXPENSE ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule COGS2 removes $25,876,000 from Forward-Looking Test Period fuel expense to reflect the Company's proposal in this filing to include such expenses associated with short-term bundled non-native contracts in the net margin calculation in Tracker 70. This proposal is discussed later in Section V of my testimony, as well as the Direct Testimony of Company witness Mr. Swez.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS3 – REMOVE FUEL EXPENSE ASSOCIATED WITH NON-NATIVE SALES MARGIN.

A. Schedule COGS3 removes $3,308,000 from Forward-Looking Test Period expenses to reflect that these expenses are included in the traditional non-native sales sharing mechanism of the Company's Tracker 70.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS4 – NON-JURISDICTIONAL FUEL EXPENSE ASSOCIATED WITH SPECIAL CONTRACT 1-B.

A. Schedule COGS4 removes $2,136,000 from Forward-Looking Test Period fuel expense to reflect that these MISO administrative fee expenses, like the associated revenues, should be considered non-jurisdictional for ratemaking purposes. In addition, $74,772,000 is being removed from Forward-Looking Test Period purchased power expenses as these are considered a "pass through." These purchased power costs to serve this load are expected to be offset by the applicable revenues. Given that the Company generation will not be used to serve this load, there is no impact to native customers and, therefore, these amounts are being removed from the revenue requirements. See testimonies of Company witnesses Mr. Swez and Ms. Diaz for further information regarding Special Contract 1-B.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS5 – NON-ONGOING FUEL EXPENSE FOR SPECIAL CONTRACT 4.

A. Schedule COGS5 removes $621,000 of fuel expenses (both coal and natural gas costs) associated with Special Contract 4 as this represents a non-ongoing amount forecasted for the construction period.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS6 – FUEL EXPENSE FOR EXPIRING WHOLESALE CONTRACTS.

A. Schedule COGS6 removes $22,554,000 of fuel expenses associated with the two native wholesale contracts that are expiring at the end of 2025, as mentioned earlier in my testimony.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE COGS7 – REMOVE TRACKER-RELATED COST OF GOODS SOLD DEFERRALS.

A. Schedule COGS7 removes a credit of $4,895,000 from Forward-Looking Test Period operating expenses for the effect of the deferral of tracker-related fuel and purchased power costs, representing timing differences between when the expense was incurred versus when the expense is recovered through tracker revenues.

C. <u>O&M</u>

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULES OM1 AND OM2.

A. Schedule OM1 summarizes projected 2025 O&M as adjusted for forecasting and pro forma adjustments by account. Schedule OM2, summarizes the *pro forma* adjustments made to O&M (excluding fuel and purchased power shown on the COGS schedules) on Schedules OM3 through OM16. I am sponsoring Schedules OM3 - OM7, OM10, and OM13. Company witness Ms. Graft sponsors the remaining Schedules supporting the O&M *pro forma* adjustments.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM3 – REMOVE RECB/MVP RELATED COSTS.

A. Schedule OM3 removes $1,571,000 from Forward-Looking Test Period O&M expenses for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues for these projects.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM4 – REMOVE EXPENSES REMAINING IN THE ENERGY EFFICIENCY TRACKER ("TRACKER 66").

A. Schedule OM4 remove $36,846,000 from Forward-Looking Test Period expenses for EE O&M costs that will be recovered via Tracker 66 under the Company's rate proposal, as discussed in the testimony of Company witness Ms. Lilly. Costs that will be recovered via trackers should be excluded from the development of new base rates.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM5 – REMOVE EXPENSES STAYING IN THE TDSIC TRACKER.

A. Schedule OM5 removes $18,838,000 from Forward-Looking Test Period operating expenses for O&M that will be recovered via the TDSIC tracker under the Company's rate proposal, as discussed in the testimony of Company witness Ms. Lilly. Costs that will be recovered via trackers should be excluded from the development of new base rates.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM6 – REMOVE PUBLIC UTILITY FEE FOR REVENUES REMAINING IN TRACKERS.

A. The Company converts operating expenses to a revenue requirement utilizing a revenue conversion factor that includes (among other items) a provision for the public utility fee assessed by the Commission. Schedule OM6 removes $26,000 from Forward-Looking Test Period operating expenses for public utility fee costs associated with the $17,281,000 in revenues that will be recovered via trackers under the Company's rate proposal. The calculation of the adjustment utilizes a forecasted public utility fee rate per dollar of revenue of 0.151%. Workpaper

OM1 supports the calculation of the forecasted public utility fee rate and the *pro forma* adjustment.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM7 – REMOVE TRACKER-RELATED DEFERRALS.

A. Schedule OM7 increases Forward-Looking Test Period operating expenses by $9,899,000 to remove the effect of the deferral of O&M expenses associated with the ECR and TDSIC trackers. These deferrals represent the normal timing differences between when the O&M expenses are incurred versus when the O&M expenses are recovered through tracker revenues.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM10 – REMOVE OPRB COSTS FROM O&M EXPENSE.

A. Schedule OM10 adjusts the Forward-Looking Test Period employee benefits costs charged to FERC account 926 to set the level of OPRB expense included in O&M to zero. Please see Workpaper OM6 for support for the $5,850,000 adjustment amount. This adjustment was made because the level of external funding in the Grantor Trust, established to fund payment of future OPRB liabilities, is sufficient to pay benefits in the foreseeable future without additional funding. This treatment for cost-of-service purposes is consistent with that used in the Company's last retail base rate case in Cause No. 45253. Company witness Ms. Caldwell provides additional background on the Grantor Trust and the Company's OPRB benefits. See Section VII of my testimony for a discussion of the Company's proposal to credit customers for excess funding in the Grantor Trust.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OM13 – NORMALIZE MAJOR STORM EXPENSES.

A. As discussed in more detail later in Section VI of my testimony, the Company is requesting to update the amount built into base rates for normalized major storm expenses based on a more recent five-year historical average (2019 to 2023). Schedule OM13 shows an increase to the Forward-Looking Test Period operating expenses of $2,746,000 to reflect this normalized level of major storm expenses.

D. <u>Other Taxes</u>

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OTX1 – SUMMARY.

A. Schedule OTX1 summarizes the *pro forma* adjustments made to Taxes Other Than Income Taxes on Schedules OTX2 through OTX8. I sponsor and discuss Schedules OTX3 and OTX5 through OTX8. Company witness Ms. Graft sponsors Schedules OTX2 and OTX4.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OTX3 – REMOVE TDSIC-RELATED PROPERTY TAX DEFERRALS.

A. Schedule OTX3 removes a credit of $851,000 from Forward-Looking Test Period property taxes to remove the TDSIC tracker-related deferral amount associated with property taxes. This deferral represents the normal timing differences between when the property tax expense is incurred versus when the property tax will be recovered through tracker revenues.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OTX5 – REMOVE OTHER TAX EXPENSE FOR RECB/MVP PROJECTS.

A. Schedule OTX5 removes $13,000 from Forward-Looking Test Period payroll taxes and $142,000 from Forward-Looking Test Period property taxes for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues and O&M expenses for these projects.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OTX6 – REMOVE PAYROLL TAXES ASSOCIATED WITH EE EXPENSES REMAINING IN THE TRACKER.

A. Schedule OTX6 removes $379,000 from Forward-Looking Test Period payroll taxes for items remaining in Tracker 66.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OTX7 – REMOVE PAYROLL TAXES ASSOCIATED WITH TDSIC EXPENSES REMAINING IN THE TRACKER.

A. Schedule OTX7 removes $178,000 from Forward-Looking Test Period payroll taxes to reflect that these amounts will remain in the TDSIC tracker.

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C SCHEDULE OTX8 – REMOVE OTHER TAX EXPENSE FOR MAJOR STORM NORMALIZATION.

A. Schedule OTX8 increases Forward-Looking Test Period payroll taxes by $196,000 to reflect a normalized level of major storm expenses. As discussed in more detail later in Section VI of my testimony, the Company is requesting to update the amount built into base rates for a normalized level of major storm expenses based on a more recent five-year historical average.

V. TRACKERS

A. RTO Non-Fuel Costs and Revenue Adjustment Tracker

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RTO TRACKER?

A. The Company is not proposing any changes to the operation of the RTO Tracker in this proceeding but is updating the amounts embedded in base rates for the RTO non-fuel costs and transmission revenues to reflect forecasted levels for 2025. The Company will continue tracking the actual amounts experienced for these items above and below the amounts in base rates through this tracker.

Q. ARE YOU PROPOSING ANY CHANGES TO THE TARIFF FOR THE RTO TRACKER?

A. In addition to updating the applicable amounts in base rates (shown on the face of the tariff), the Company will be making some minor labeling updates to the tariff. Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the RTO Tracker are attached to my direct testimony as Attachments 4-A (SES) and 4-B (SES).

Upon receipt of the Commission order in this proceeding, the Company will update the allocation factors for the RTO Tracker tariff to reflect the approved amounts from the cost-of-service study and will also update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fees approved in this proceeding. The complete RTO Tracker tariff with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

B. Reliability Tracker

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RELIABILITY TRACKER?

A. The Company is proposing the following changes to the Reliability Tracker:

- Retaining a sharing mechanism for net margins realized on short-term bundled non-native sales. The Company proposes to reset the base amount to zero and to share 100% of net margins up to a $5 million threshold with customers. Any positive net margins above that level would be shared 50/50 between customers and shareholders.
- Update the proposed annual base amount for Power Share® bill credits in base rates to zero and to recover actual costs for this program entirely through the Reliability Tracker.

I will discuss both changes further in this section.

Q. WHAT CHANGES, IF ANY, IS THE COMPANY PROPOSING TO THE CURRENT SHARING MECHANISM FOR TRADITIONAL NON-NATIVE SALES WITHIN THE RELIABILITY TRACKER?

A. The Company is not proposing any changes to this portion of the Reliability Tracker. Positive margins on traditional non-native sales will continue to be shared 100% with customers with no amount embedded in base rates. These traditional non-native sales are essentially sales of hourly excess generation (above what is needed to serve load) in the MISO energy market.

Q. CAN YOU PLEASE DESCRIBE WHAT THE COMPANY IS REFERRING TO AS SHORT-TERM BUNDLED NON-NATIVE SALES?

A. Yes. The Company is using this term to describe a specific type of non-native contract that combines sales of both capacity and energy and is short-term in nature (five years or less). The negotiated contract prices are designed to cover the energy costs and make a contribution to fixed costs. These short-term bundled non-native agreements have been structured to meet a changing wholesale customer need and are priced to compete at current market prices. For a more detailed discussion on this topic, please refer to the direct testimony of Company witness Mr. Swez.

Q. PLEASE EXPLAIN HOW NET MARGINS ON THE SHORT-TERM BUNDLED NON-NATIVE CONTRACTS ARE CURRENTLY TREATED IN THE COMPANY'S TRACKER 70 FILINGS.

A. In the Company's last base rate case, the Commission approved the inclusion of these short-term bundled non-native sales in Tracker 70 and found at the time that base rates should include a credit of $11.748 million for the retail portion of 2020 forecasted net margins for these types of sales. Net margins above and below this amount (down to zero) are shared 50/50 between customers and shareholders.

Q. WHAT CHANGES IS THE COMPANY PROPOSING IN THIS PROCEEDING FOR SHORT-TERM BUNDLED NON-NATIVE SALES?

A. The Company is proposing to continue to include the net margin from any short-term bundled non-native sales within the Reliability Tracker, with the amount in base rates being reset to zero. Positive net margins, up to a threshold of $5 million, will be shared 100% with customers. Any net margins in excess of this threshold amount would be shared equally (50/50) between the Company and customers.

Q. WHY IS THE COMPANY PROPOSING IN THIS PROCEEDING THAT THE AMOUNT IN BASE RATES SHOULD BE SET AT ZERO FOR THESE SHORT-TERM BUNDLED NON-NATIVE SALES?

A. There are a couple of reasons for this proposal. The first reason is that the Company has not realized positive margins on these types of sales since the first contract expired in mid-2021. The Forward-Looking Test Period for these short-term bundled non-native sales reflects a negative margin of $5.789 million.

The second reason is that MISO has recently moved to a Seasonal Accredited Capacity ("SAC") construct for its annual capacity auction, beginning with Planning Year 2023/2024. As a result of the changes associated with the new SAC construct, it is extremely challenging for the Company to forecast margins on these contracts with any level of certainty. Company witness Mr. Swez provides details on the specific changes associated with the SAC construct and the associated challenges to the Company in managing capacity.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE RELIABILITY TRACKER WITH REGARDS TO CAPACITY COSTS AND/OR REVENUES?

A. The Company is not proposing any changes to this portion of the Reliability Tracker. The Company provides information in the annual Tracker 70 filing for capacity purchases and sales made during the reporting period. The capacity purchases and sales are netted over the full twelve-month reporting period. If the Company is in a net purchase position over the full reporting period, the retail portion of the net purchase is included as a charge in the Reliability Tracker. If the Company is in a net sales position, the net revenue amount is included in the margin calculation for traditional non-native sales, which are shared 100% with native customers.

Q. WHAT CHANGES ARE BEING PROPOSED FOR THE POWERSHARE® PROGRAM IN THE RELIABILITY TRACKER?

A. Tracker 70 provides for the tracking (both up and down) of actual PowerShare® premiums and energy credits. If the actual costs for the reporting period are more than the annual test period expense level approved in the last base rate case, than the additional costs are included in the Tracker 70 filing. In Cause No. 45803, the Company requested and received approval of its three-year plan for Energy Efficiency programs for calendar years 2024 to 2026, which included a new Non-Residential Demand Response ("DR") program to be offered beginning January 2024. The new DR program shares similarities with the PowerShare® program tracked in Tracker 70.

It is anticipated that many of the current participants in the PowerShare® program will elect to instead participate in the new DR program because of additional benefits that program will offer. Resetting the amount in base rates for the existing PowerShare® program to zero, while establishing a level in base rates for this new DR program, reduces the likelihood that the Company initially over-collects from customers for these programs.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT TARIFF FOR THE RELIABILITY TRACKER?

A. Yes. The Company is proposing to update the amount reflected in base rates for bill credits under the PowerShare® program. In this instance, the Company is proposing the base amount be set at zero for the reasons provided above. Modifications are also being made to show the new sharing proposal for short-term bundled non-native sales, also described in detail above. Lastly, the Company will be making some minor labeling updates to the tariff. Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Reliability Tracker are attached to my direct testimony as

Attachments 4-C (SES) and 4-D (SES).

Upon receipt of the Commission order in this proceeding, the Company will update the allocation factors for the Reliability Tracker tariff to reflect the approved amounts from the cost-of-service study and will also update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fees approved in this proceeding. The complete Reliability Tracker tariff with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

C. <u>Renewables Tracker</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RENEWABLES TRACKER?

A. The Company is proposing to roll the net book value (original cost investment less accumulated depreciation) of all in-service renewables plant as of the end of the Forward-Looking Test Period into base rates. Additionally, the Forward-Looking Test Period level of O&M will be included in base rates, as will the depreciation associated with the investment rolled into rate base.

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

- remove the investment and O&M amounts included in base rates;
- recalculate the depreciation on the remaining investment (if any) using the new depreciation rates approved in this proceeding;
- change the 9.7% ROE used in the cost of capital calculation to the new

ROE approved in this proceeding;

- change the allocations to rate classes used in the calculation of rates to use the final 12 Coincident Peak ("CP") production demand allocators from this proceeding instead of the current allocators approved in Cause No. 45253; and
- make administrative updates, if needed, to the tariff pages for consistency across trackers and to reflect specific requests being made in this proceeding.

This proposed treatment and changes are in accordance with the terms of the Commission's Orders in Cause Nos. 44767 and 45002 approving rate recoveries for Markland Uprate projects and Atterbury/Nabb projects, respectively.

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

A. Yes. The Company is proposing that post-in-service carrying costs and any credits from the sale of renewable energy certificates ("RECs") are not included in base rates but rather continue to be tracked in the Renewables Tracker. The post-in-service carrying costs and REC sales are non-recurring and variable in nature, so these items would be best managed through the tracker, until such time as the Renewable Tracker is no longer warranted.

In addition, once the Company is able to utilize the ITCs for the applicable renewable projects on its corporate consolidated federal income tax return, an additional credit for the retail jurisdictional portion of the associated ITC amortization would be included in the Renewables Tracker. These credits have not been included in the proposed base rates in this proceeding to ensure compliance with the federal income tax normalization requirements because the Company does not anticipate being able to utilize these specific credits until after the Forward-Looking Test Period.

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING RENEWABLES INVESTMENT AND COSTS CURRENTLY INCLUDED IN THE RENEWABLES TRACKER REASONABLE?

A. Yes. 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 Markland Uprate and Atterbury/Nabb Settlement Agreements. To continue to track the post-in-service carrying costs and any REC sale net proceeds in the Renewables Tracker, along with any incremental new investment and related depreciation and O&M, is a reasonable way to recover the non-routine and variable Renewables Tracker costs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE RENEWABLES TRACKER 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 tracker rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO THE CURRENT RENEWABLES TRACKER TARIFF?

A. Yes. The Company is proposing some minor labeling updates to the tariff. Copies of the red-lined and clean revised tariff sheets containing the language, header, and format changes, if any, for the Renewables Tracker are attached to my testimony as Attachments 4-E (SES) and 4-F (SES).

Upon receipt of the Commission order in this proceeding, the Company will update the allocation factors to reflect the approved amounts from the cost-of-service study and will also update the revenue conversion factor to reflect the provision for uncollectible accounts expense and public utility fees approved in this proceeding. The complete Renewables Tracker tariff with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

VI. <u>REQUEST FOR CONTINUATION OF DEFERRAL</u>

A. <u>Storm Normalization Reserve</u>

Q. WHAT IS THE COMPANY PROPOSING RELATED TO MAJOR STORM EXPENSES?

A. In Cause No. 45253, the Commission approved a Major Storm Damage Restoration Reserve ("Major Storm Reserve") based on the Company's five-year average of major storm expense. The Company is requesting to continue this mechanism and is seeking approval of its request to update the amount built into retail base rates for a normalized level of major storm expenses. The updated amount of approximately $15.6 million is based on a five-year historical average of such costs for calendar years 2019 through 2023. The updated amount was calculated in the same manner as the adjustment approved by the Commission in the Company's last base rate case in Cause No. 45253. A *pro forma* adjustment was made to increase the Forward-Looking Test Period amount for major storms from $12.7 million to the $15.6 million level. In addition to establishing a normalized level in base rates, the Company is proposing to continue to utilize the Major Storm Reserve to track differences between the operating costs incurred and the amount collected in base rates. Any under-recovery would be recorded to a Regulatory Asset and any over-recovery would be recorded as a Regulatory Liability. The net amount for the Major Storm Reserve would be addressed for recovery in the next retail base rate case.

Q. FOR PURPOSES OF THIS PROPOSAL, HOW IS THE COMPANY DEFINING A MAJOR STORM?

A. Company witness Mr. McCorkle provides information in his testimony on this subject. Mr. McCorkle's testimony includes a table showing Duke Energy Indiana's historical 2019 through 2023 transmission and distribution costs incurred for major storms based on Major Event Days ("MEDs"). Generally speaking, a storm is classified as an MED when a major reliability event causes a utility to shift into a crisis mode of operation in order to adequately respond. As further described in Mr. McCorkle's testimony, the Institute of Electrical and Electronic Engineers ("IEEE") 1366 statistically defines an MED as a day in which the daily System Average Interruption Duration Index ("SAIDI") exceeds an MED threshold value (calculated from a 5-year average daily SAIDI). See Workpaper OM3-SES for the supporting calculation for the five-year historical average for major storm costs that was used to determine the normalized level.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO MAINTAIN A MAJOR STORM RESERVE?

A. As evidenced by the historical cost information shown in Mr. McCorkle's testimony, the costs for major storms vary significantly year-to-year based on the actual number of MEDs declared and the types of restoration efforts required. During the 2019 to 2023 historical period alone, costs varied from a low of $5.0 million in one year to a high of $41.4 million in another year. Although the Company is proposing to normalize major storm costs for establishing base rates, the timing, frequency, and costs for such major storms are unpredictable and therefore challenging for the Company to establish a precise amount in base rates to cover its prudently incurred costs (nothing more or nothing less). The Company believes its proposal to continue with the Major Storm Reserve is reasonable and balances the interests of both the Company and its customers by smoothing out these costs and providing for the Company to be able to recover no more or less than its actual costs.

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS CASE WITH REGARDS TO THE AUGUST 31, 2023 BALANCE IN THE MAJOR STORM RESERVE?

A. As of December 31, 2023, the Major Storm Reserve had a regulatory asset balance of $11.2 million. Prior to the significant major storm costs incurred during 2023, the Major Storm Reserve had a regulatory liability balance. As costs exceeded the annualized level during the year, the balance turned to a regulatory asset balance in September 2023. Given that the Major Storm Reserve is functioning as designed and the balance is slowly coming down, the Company proposes to leave the balance as is (to be adjusted with future year overages and underages and reviewed in the next base rate case) and simply update the normalized level to reflect the more recent five-year average.

VII. <u>OTHER</u>

Q. DO YOU HAVE ANY ADDITIONAL TOPICS YOU WOULD LIKE TO COVER IN YOUR TESTIMONY?

A. Yes. I would like to cover the following additional items:

- Explain the Company's proposal related to the *GoGreen* Tariff No. 56;
- Provide an update on the EV Fast Chargers and proposed ratemaking; and
- Explain the Company's proposal to refund amounts associated with excess funding in the Grantor Trust which is used to fund OPRB costs.

A. *GoGreen* Tariff

Q. WHAT IS THE COMPANY SEEKING WITH REGARDS TO THE *GOGREEN* PROGRAM?

A. The Company is requesting Commission authorization for certain changes in the *GoGreen* Tariff No. 56 ("*GoGreen*" or "Tariff 56") program, which I will explain below.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE EXISTING *GOGREEN* PROGRAM.

A. *GoGreen* is a voluntary, below-the-line program, which allows customers to purchase RECs to help support renewable energy or work towards the customer's own sustainability goals. The program has been in existence for over ten years. In addition to the subscription program, there is also an option under the *GoGreen* program to assist large business customers with meeting their renewable goals. RECs needed to support the program are currently purchased by Duke Energy Indiana on the open market and retired on behalf of the program participants. Administrative costs for the program, as well as the costs to purchase and retire the RECs, are recorded below-the-line and are netted against the revenues for the program. The goal for this program is to break-even, with revenues received being enough to cover the associated costs. The subscription fees can be adjusted periodically in order to achieve this goal as the cost of the RECs and/or the administrative costs change over time.

Q. WHAT SPECIFIC CHANGES TO THE *GOGREEN* PROGRAM ARE BEING PROPOSED BY THE COMPANY AT THIS TIME?

A. Instead of exclusively purchasing RECs on the open market, the Company proposes to begin using RECs associated with an upcoming PPA, once the location is on-line, to satisfy subscriptions under the *GoGreen* program. Customers have expressed a preference for having access through the program to locally sourced RECs.

Q. PLEASE DESCRIBE THE TERMS OF THE PPA YOU ARE REFERENCING.

A. On October 25, 2023 in Cause No. 45907, the Commission approved the Company's proposed solar power purchase agreement between Duke Energy Indiana and Ranger Power LLC for the project known as Speedway Solar (the "Speedway Solar PPA"). The Speedway Solar PPA is being developed in Shelby County, Indiana and will have an installed capacity of approximately 199 megawatts. The contract has a term of 20 years and is expected to generate roughly 426,000 RECs per year once it is on-line, which is estimated to be in late 2025. The specific needs of the *GoGreen* subscription program are relatively small, but the additional RECs generated from the Speedway Solar PPA would be available to large business customers that want to purchase locally sourced solar RECs through the *GoGreen* program.

Q. HOW WOULD THE RECS BE PRICED?

A. To support use in the *GoGreen* program, a price will need to be set for the Speedway Solar RECs. The Company plans to set this price annually based on the last twelve-month average national voluntary wind/solar REC pricing. The *GoGreen* program will compensate Duke Energy Indiana at this price for the RECs purchased for both the subscription portion and the large business portions of the program. The proceeds from the sale of RECs to the *GoGreen* program will flow through to all customers via the quarterly Fuel Adjustment Clause ("FAC") proceedings.

Q. WHAT WOULD HAPPEN WITH ANY RECS REMAINING FOR THE PRIOR VINTAGE YEAR THAT WERE IN EXCESS OF WHAT WAS NEEDED FOR THE *GOGREEN* PROGRAM?

A. Any Speedway Solar PPA RECs remaining for the prior vintage year could be retired on behalf of all Duke Energy Indiana customers and those customers would be able to claim the environmental benefits for the renewable power. Retiring RECs is a best practice, reducing "greenwashing" concerns and allowing for all retail customers to claim solar in the residual mix.

Q. ARE ANY CHANGES NEEDED TO THE *GOGREEN* TARIFF TO ACCOMMODATE THE COMPANY'S PROPOSAL?

A. It is my understanding that the current tariff language is sufficient to allow for the proposed changes to the program without requiring any updates to the tariff language, as the existing language allows for flexibility in sourcing of the RECs.

A copy of the tariff is included in the tariffs filed by Company witness Mr. Flick in Attachment 7-A (RAF).

B. <u>DC Fast Charging</u>

Q. PLEASE DESCRIBE THE COMPANY'S DC FAST CHARGING PROGRAM, KNOWN AS PARK & PLUG.

A. As discussed further in Cause No. 45616, Duke Energy Indiana and seven other electric utilities in Indiana were awarded $5.5 million to roll out and operate a 61 location DC Fast Charge Network across the State by the end of 2023. These funds were available from the Indiana Department of Environmental Management ("IDEM") Volkswagen ("VW") Beneficiary Mitigation Fund. Duke Energy Indiana was approved to install fast charging at 17 locations, ranging from large national retailers, municipal properties, to small independent shops across the Company's service territory. Each charging location has two dual port chargers. Each charger is capable of a total output of 150kW or higher.

Q. WHAT IS THE INSTALLATION STATUS OF THE DC FAST CHARGERS AT THE APPROVED 17 LOCATIONS?

A. As of the end of 2023, there were six sites completed at Rochester, Batesville, Franklin, Fishers, Seymour, and Edinburgh. As of the time of this filing, four additional sites were completed at Princeton, Corydon, New Castle, and Shelbyville. The Company expects the remaining seven locations - Bedford, Versailles, Madison, Bloomington, Kokomo, Brownsburg, and Plainfield - will be operational by the end of May 2024.

Q. ARE THESE DC FAST CHARGING ASSETS REFLECTED IN THE COMPANY'S RATE BASE IN THIS BASE RATE PROCEEDING?

A. Yes. The value of these assets as of the end of the Base Period (August 31, 2023) of approximately $3.7 million is included in the starting balance of the Company's rate base calculation. The Company has forecasted $2.0 million of additions through the end of May 2024. Receipt of the IDEM/VW settlement funds of $1.5 million was forecasted for June 2024. The value of these assets (net of the settlement funds) as of June 30, 2024 is approximately $4.2 million and is reflected in the Company's forecast for distribution plant-in-service. The forecasted amount for these assets, net of accumulated depreciation, is $3.9 million and $3.5 million as of June 30, 2024 and December 31, 2025, respectively.

Q. WHAT RATE DOES THE COMPANY CHARGE FOR USE OF THE DC FAST CHARGING STATIONS?

A. In Cause No. 45616, the Company received authorization for a new EVFC Tariff. The EVFC Tariff rate is derived from an Indiana statewide average of existing, comparable public charging stations with greater than 50 kW charging output capacity that are publicly accessible 24-hours per day. Setting rates in this manner provides a reasonable and flexible means to price fast charging services that neither undercuts other market participants nor overburdens EV drivers. The Petitioner reviews these rates monthly and provides an update on these rates quarterly to the Commission. If the statewide average changes by more than 10%

then the Company (under the supervision of Company witness Mr. Flick) files an updated tariff with the Commission (through a 30-day process) to update the rate. See Attachment 7-A (RAF) filed by Company witness Mr. Flick for a clean copy of the EVFC Tariff.

Q. HOW WILL THE COMPANY RECEIVE REVENUES ASSOCIATED WITH THE USE OF THE CHARGERS?

A. EV Connect, the network provider that Duke Energy Indiana is using for the chargers, is working through a third-party (Bill.com) to provide a lump sum ACH payment to the Company for the charging revenues. There will be one deposit each quarter that covers all 17 sites.

Q. WHAT OPERATION AND MAINTENANCE COSTS ARE ANTICIPATED FOR THESE SITES?

A. The hardware at these sites is under manufacturer warranty for the first five years. Absent unexpected issues such as weather and vandalism, the Company expects O&M costs to be minimal. EV Connect, as the network provider, will be paid an annual network fee and will be responsible for remotely monitoring the operability of the hardware as well as the functionality that allows public use of the assets.

Q. HOW WILL THE FUEL COSTS ASSOCIATED WITH THESE CHARGERS BE CALCULATED?

A. The Company will be able to track monthly kWh usage at each charging site. The fuel costs associated with this usage will be priced at the Company's system average fuel cost for the month. These fuel costs associated with providing energy to the chargers will be excluded from the Company's native fuel costs recovered through the quarterly FAC filings.

Q. YOU MENTIONED EARLIER WHAT IS INCLUDED IN THE FORECAST FOR THESE ASSETS. IS THERE ANYTHING INCLUDED IN THE FORWARD-LOOKING TEST PERIOD FOR THE REVENUES OR FUEL AND O&M EXPENSES ASSOCIATED WITH THE EV CHARGERS?

A. No, there is not.

Q. WHAT IS THE COMPANY PROPOSING WITH REGARDS TO THE REVENUES RECEIVED FROM USE OF THE CHARGERS?

A. The Company proposes using the revenues received from use of the EV chargers to cover the costs associated with station operations, which includes fuel costs, network fees, and O&M. If the EV charging revenues received are more than what is needed to cover these costs, the excess revenues will be credited to customers. To flow the credits back to customers in a timely manner, the Company is proposing to include any credits in the Company's quarterly FAC filings.

C. Refund of Excess OPRB Funds

Q. YOU MENTIONED EARLIER IN YOUR TESTIMONY THAT THE GRANTOR TRUST FOR OPRB BENEFITS WAS SUFFICIENTLY FUNDED. PLEASE EXPLAIN WHAT HAPPENS TO FUNDS IN THE

GRANTOR TRUST ONCE ALL OPRB BENEFITS HAVE BEEN PAID OUT TO RETIREES.

A. Under the terms of the Commission's Order in Cause No. 40388 approving the Company's OPRB Settlement Agreement with OUCC under which the Grantor Trust was established to fund OPRB ("OPRB Settlement"), the amounts held by the Grantor Trust are restricted to the payment of OPRB liabilities and any taxes or expenses incurred by the Grantor Trust. Once all OPRB liabilities, taxes, and expenses have been paid (not expected to occur until sometime after 2070), any remaining retail jurisdictional assets shall be credited to retail customers unless the settling parties to the OPRB Settlement Agreement agree to alternative treatment. The OPRB 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.

Q. IN ADDITION TO THE REMOVAL OF OPRB COSTS FROM THE COST OF SERVICE AND THE DISCONTINUATION OF FUNDING, IS DUKE ENERGY INDIANA PROPOSING ANYTHING ELSE IN THIS CASE REGARDING THE GRANTOR TRUST?

A. Yes. Due to changes over time in the Company's benefit plans for retirees, generally reducing or eliminating OPRB benefits for existing and new employees, coupled with favorable investment performance for the contributions made to the Grantor Trust, the Company is recommending the Commission approve a refund of a portion of Grantor Trust funds to retail customers of $75,000,000 (or approximately 50% of the balance as of December 31, 2023) over two years via the Company's Tariff No. 67, rather than waiting until the end of the life of the benefit plans to make refunds to customers. The Grantor Trust has become over-funded due primarily to two reasons: 1) the post-retirement benefit plan changes (reductions in benefits for existing employees and eliminations of eligibility for new employees); and 2) required funding pursuant to the OPRB Settlement Agreement that essentially set the level of annual funding at the amount of the OPRB expense included in the cost-of-service in Cause No. 42359. In the Company's last rate case, the funding level was reviewed, and the Company proposed, and the Commission approved, discontinuation of funding.

Q. IS SUCH AN EARLY PARTIAL REFUND OF GRANTOR TRUST FUNDS ALLOWED UNDER THE GRANTOR TRUST AGREEMENT?

A. Yes. Section 14 – Amendment or Termination of the Grantor Trust Agreement part (c) states in part:

> Alternatively, if the Company substantially reduces or eliminates OPRBs, and any state or federal regulatory agency having jurisdiction determines that the Trust fund is over-funded, then such agency may order the excess funds removed from the Trust and returned to the Company. Thereafter, the portion of that partial liquidation of Trust assets shall be paid or credited to the Company's customers, unless otherwise agreed to by the state or federal regulatory agency having jurisdiction.

Q. WILL THE PARTIAL REFUND JEOPARDIZE THE COMPANY'S ABILITY TO PAY FOR FUTURE OPRB PAYMENTS TO RETIREES AND RELATED EXPENSES OUT OF THE GRANTOR TRUST?

A. The Company's analysis indicated this level of refund should still provide adequate funds to pay future benefits and related expenses. The Company will reevaluate the sufficiency of the Grantor Trust funding in the Company's next retail base rate case. See Workpaper 1-SES for an analysis of the impact on the Grantor Trust balance of the proposed partial refund given forecasted benefit payment projections.

Q. WHAT IS THE COMPANY REQUESTING OF THE COMMISSION IN THIS PROCEEDING REGARDING THE COMPANY'S PROPOSED EARLY REFUND OF GRANTOR TRUST FUNDS?

A. The Company requests that the Commission determine that the Grantor Trust is overfunded due to Company reduction of OPRBs and direct the Company to refund to retail Customers $75,000,000 over two years via Tracker 67.

VIII. CONCLUSION

Q. WERE ATTACHMENTS 4-A (SES) THROUGH 4-F (SES) PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

Cause No. 46038

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: ______________________
Suzanne E. Sieferman

Dated: April 4, 2024

DUKE ENERGY INDIANA, LLC
1000 E. Main Street
Plainfield, IN 46168

IURC No. ~~15~~16
~~Fifth Revised~~Original Tariff~~Sheet~~ No. 68
~~Cancels and Supersedes~~
~~Fourth Revised Sheet No. 68~~

~~STANDARD CONTRACT RIDER~~-TARIFF NO. 68 -
REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for operation and maintenance expense treatment of RTO Non-Fuel Costs and Revenues. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

A. The RTO Non-Fuel Costs and Revenue Adjustment by Rate Group shall be determined by multiplying the RTO Non-Fuel Costs and Revenue Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours for the applicable billing cycle months in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service. RTO Non-Fuel Costs and Revenue Adjustment Factor Per Rate Group =

$$\frac{(NFC - (a - b)\,c)\,d}{s}$$

where:

1. "NFC" is the net Non-Fuel Costs and Credits forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke for mandated participation in regional transmission organizations under the Open Access Transmission and Energy Markets Tariff for the MISO ("MISO TEMT") or any successor Tariff, including applicable PJM non-fuel charges and credits related to the operation of Duke Energy Indiana's Madison Generating Station.

2. "a" is the annual level of forecasted RTO Non-Fuel Costs included in the determination of basic charges for service in Cause No. ~~45253~~ xxxxx ($~~59,998,000~~76,965,000).

3. "b" is the annual level of forecasted RTO transmission revenues included in the determination of basic charges for service in Cause No. ~~45253~~ xxxxx ($~~23,540,000~~40,000,000).

4. "c" is the individual retail rate group's allocated share of the Company's retail peak demand developed for cost of service purposes in Cause No. ~~45253~~ xxxxx expressed as a percentage of the Company's total retail peak demand.

5. "d" is the revenue conversion factor used to convert the applicable charges to operating revenues.

6. "s" is the individual retail rate group's reported kilowatt-hour sales for the twelve-month period from July through June as a proxy for the relevant billing cycle months for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

7. The RTO Non-Fuel Costs and Revenue Adjustment Factor per Rate Group shall be further modified to reflect the difference between the incremental base monthly fees actually charged or credited to the retail electric customers and the incremental base monthly fees to be charged or credited to the retail electric customers during billing cycle months, as determined above.

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1000 E. Main Street
Plainfield, IN 46168

**TARIFF NO. 68 - REGIONAL TRANSMISSION OPERATOR ("RTO")
NON-FUEL COSTS AND REVENUE ADJUSTMENT**

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for operation and maintenance expense treatment of RTO Non-Fuel Costs and Revenues. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

A. The RTO Non-Fuel Costs and Revenue Adjustment by Rate Group shall be determined by multiplying the RTO Non-Fuel Costs and Revenue Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours for the applicable billing cycle months in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service. RTO Non-Fuel Costs and Revenue Adjustment Factor Per Rate Group =

$$\frac{(NFC - (a - b)\,c)\,d}{s}$$

where:

1. "NFC" is the net Non-Fuel Costs and Credits forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke for mandated participation in regional transmission organizations under the Open Access Transmission and Energy Markets Tariff for the MISO ("MISO TEMT") or any successor Tariff, including applicable PJM non-fuel charges and credits related to the operation of Duke Energy Indiana's Madison Generating Station.

2. "a" is the annual level of forecasted RTO Non-Fuel Costs included in the determination of basic charges for service in Cause No. xxxxx ($76,965,000).

3. "b" is the annual level of forecasted RTO transmission revenues included in the determination of basic charges for service in Cause No. xxxxx ($40,000,000).

4. "c" is the individual retail rate group's allocated share of the Company's retail peak demand developed for cost of service purposes in Cause No. xxxxx expressed as a percentage of the Company's total retail peak demand.

5. "d" is the revenue conversion factor used to convert the applicable charges to operating revenues.

6. "s" is the individual retail rate group's reported kilowatt-hour sales for the twelve-month period from July through June as a proxy for the relevant billing cycle months for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

7. The RTO Non-Fuel Costs and Revenue Adjustment Factor per Rate Group shall be further modified to reflect the difference between the incremental base monthly fees actually charged or credited to the retail electric customers and the incremental base monthly fees to be charged or credited to the retail electric customers during billing cycle months, as determined above.

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1000 East Main Street
Plainfield, Indiana 46168

IURC No. 16~~15~~
~~Fourth Revised~~ Original Tariff ~~Sheet~~ No. 70
~~Cancels and Supersedes~~
~~Third Revised Sheet No. 70~~
Page 1 of 3

TARIFF ~~STANDARD CONTRACT RIDER~~ NO. 70 -
RELIABILITY ADJUSTMENT

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the net jurisdictional cost of reliability purchases, peak load management costs, and net profits from non-native sales, in accordance with the following formula:

Reliability Adjustment Factor:

$$\left((a*c)d+(b*d)-(e*c)d-(f*c)d-\left(\frac{(g\cancel{f}*c)\cancel{-11{,}748{,}000}}{2}\right)d\right)*\left(\frac{1}{s}\right)$$

where:

1. "a" equals year-round purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with reliability purchases as approved by the Commission. The total cost of reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.

2. "b" is the total year-round amount of bill credit provided to customers ~~under the Company's PowerShare® program~~ including any additional demand response amounts determined to be includable by the Commission~~, less the annual level built into base rates in Cause No. 45253 ($9,911,000)~~.

3. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. ~~45253~~xxxxx.

4. "d" is the individual retail rate group's allocated percentage share of the Company's average ~~four~~ twelve monthly coincident retail peak demands as developed for cost of service purposes in Cause No. ~~45253~~xxxxx.

5. "e" represents actual net profits realized from non-native sales of excess generation to MISO.

6. "f" represents actual net profits realized from ~~remaining non-native sales (excludes amount in "e" above), including~~ short-term bundled non-native sales up to a threshold of $5,000,000. Customer receive 100% of positive net margins on these sales up to $5,000,000 per approval in Cause No. xxxxx.

7. "g" represents actual positive net profits realized from short-term bundled non-native sales in excess of $5,000,000. Customers receive 50% of positive net margins on these sales above $5,000,000 threshold per approval in Cause No. xxxxx.

8~~7~~. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

B. The factor as computed above shall be modified to allow for the recovery of the public utility fee and uncollectible expense and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

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Plainfield, Indiana 46168

TARIFF ~~STANDARD CONTRACT RIDER~~ NO. 70 -
RELIABILITY ADJUSTMENT

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The reliability factor by rate group is as follows:

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1000 East Main Street
Plainfield, Indiana 46168

IURC No. 16
Original Tariff No. 70

TARIFF NO. 70 - RELIABILITY ADJUSTMENT

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the net jurisdictional cost of reliability purchases, peak load management costs, and net profits from non-native sales, in accordance with the following formula:

Reliability Adjustment Factor:

$$\left((a*c)d+(b*d)-(e*c)d-(f*c)d-\left(\frac{(g*c)}{2}\right)d\right)*\left(\frac{1}{s}\right)$$

where:

1. "a" equals year-round purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with reliability purchases as approved by the Commission. The total cost of reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.

2. "b" is the total year-round amount of bill credit provided to customers including any additional demand response amounts determined to be includable by the Commission.

3. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. xxxxx.

4. "d" is the individual retail rate group's allocated percentage share of the Company's average twelve monthly coincident retail peak demands as developed for cost of service purposes in Cause No. xxxxx.

5. "e" represents actual net profits realized from non-native sales of excess generation to MISO.

6. "f" represents actual net profits realized from short-term bundled non-native sales up to a threshold of $5,000,000. Customers receive 100% of positive net margins on these sales up to $5,000,000 per approval in Cause No. xxxxx.

7. "g" represents actual positive net profits realized from short-term bundled non-native sales in excess of $5,000,000. Customers receive 50% of positive net margins on these sales above $5,000,000 threshold per approval in Cause No. xxxxx.

8. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

B. The factor as computed above shall be modified to allow for the recovery of the public utility fee and uncollectible expense and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The reliability factor by rate group is as follows:

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Plainfield, Indiana 46168

~~STANDARD CONTRACT RIDER~~TARIFF NO. 73 –
RENEWABLE ENERGY
PROJECT ADJUSTMENT

Calculation of Adjustment

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh to reflect rate base treatment for investments in utility-owned renewable energy projects approved by the Commission as clean energy projects under Indiana Code 8-1-8.8 (“Renewable Energy Projects”) and recovery of related Renewable Energy Projects operating costs (depreciation, property taxes, operation and maintenance, etc.). The revenue adjustment applicable to the Company’s charges for electric service will be determined based on the following provisions:

Renewable Energy
Project Adjustment Factor by Rate Group =

$$\frac{[(a \times b \times c) + (e + f + g + h - i)] \times d}{j}$$

Where:

1. “a” is the jurisdictional cost of the Company’s cumulative capital investment in Renewable Energy Projects, including costs of completed capital projects, costs of capital projects under construction and applicable post-in-service carrying costs, net of accumulated depreciation at applicable cut-off dates. For purposes of determining the value of such capital projects for this rate mechanism, the Company’s cost as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used, subject to any limits approved by the Commission.

2. “b” is the Company’s weighted average cost of capital in accordance with Commission rule 170 IAC 4-6-14 as of the date of valuation of the Renewable Energy Projects.

3. “c” is the revenue conversion factor used to convert return to operating revenues.

4. “d” is the individual retail rate group’s jurisdictional production demand allocator used for allocation purposes in the cost of service study last approved by the Commission, as adjusted for rate migrations approved by the Commission.

5. “e” is the twelve-month forecasted jurisdictional depreciation expense applicable to the Renewable Energy Projects using Commission-approved depreciation rates converted to revenue requirements.

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~~STANDARD CONTRACT RIDER~~TARIFF NO. 73 –
RENEWABLE ENERGY
PROJECT ADJUSTMENT

6. “f” is the sum of the twelve-month forecasted jurisdictional operating expenses applicable to the Renewable Energy Projects which shall include operation and maintenance expenses, property insurance expenses, real estate and property taxes, payroll taxes, and employee benefit costs converted to revenue requirements.

7. “g” is the jurisdictional portion of federal investment tax credits applicable to the Renewable Energy Projects, amortized by the Company during the applicable twelve-month ended period, converted to revenue requirements.

8. “h” is the actual jurisdictional portion of amortizations, approved by the Commission, that were recorded during the applicable twelve-month ended period converted to revenue requirements.

9. “i” is the actual jurisdictional portion of net renewable energy credit (“REC”) proceeds from any sales during the applicable twelve-month ended period converted to revenue requirements.

10. “j” is the individual retail rate group’s adjusted billing cycle kilowatt-hour sales for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the HLF customer group such that “k” shall be the sum of kilowatts billed for the same twelve-month period.

The factor shall be further modified to reflect the difference between estimated operating costs billed and operating costs actually incurred for those costs that are recovered on a projected basis and to reflect the difference between operating costs and credits actually incurred, including return revenue requirements, operating costs, credits, and return collected from customers for operating costs and credits that are recovered on an actual basis.

The Renewable Energy Project Adjustment factor applicable to retail rate groups shall be as follows:

TARIFF NO. 73 – RENEWABLE ENERGY PROJECT ADJUSTMENT

Calculation of Adjustment

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh to reflect rate base treatment for investments in utility-owned renewable energy projects approved by the Commission as clean energy projects under Indiana Code 8-1-8.8 ("Renewable Energy Projects") and recovery of related Renewable Energy Projects operating costs (depreciation, property taxes, operation and maintenance, etc.). The revenue adjustment applicable to the Company's charges for electric service will be determined based on the following provisions:

Renewable Energy
Project Adjustment Factor by Rate Group =

$$\frac{[(a \times b \times c) + (e + f + g + h - i)] \times d}{j}$$

Where:

1. "a" is the jurisdictional cost of the Company's cumulative capital investment in Renewable Energy Projects, including costs of completed capital projects, costs of capital projects under construction and applicable post-in-service carrying costs, net of accumulated depreciation at applicable cut-off dates. For purposes of determining the value of such capital projects for this rate mechanism, the Company's cost as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used, subject to any limits approved by the Commission.

2. "b" is the Company's weighted average cost of capital in accordance with Commission rule 170 IAC 4-6-14 as of the date of valuation of the Renewable Energy Projects.

3. "c" is the revenue conversion factor used to convert return to operating revenues.

4. "d" is the individual retail rate group's jurisdictional production demand allocator used for allocation purposes in the cost of service study last approved by the Commission, as adjusted for rate migrations approved by the Commission.

5. "e" is the twelve-month forecasted jurisdictional depreciation expense applicable to the Renewable Energy Projects using Commission-approved depreciation rates converted to revenue requirements.

6. "f" is the sum of the twelve-month forecasted jurisdictional operating expenses applicable to the Renewable Energy Projects which shall include operation and maintenance expenses, property insurance expenses, real estate and property taxes, payroll taxes, and employee benefit costs converted to revenue requirements.

TARIFF NO. 73 – RENEWABLE ENERGY PROJECT ADJUSTMENT

7. “g” is the jurisdictional portion of federal investment tax credits applicable to the Renewable Energy Projects, amortized by the Company during the applicable twelve-month ended period, converted to revenue requirements.

8. “h” is the actual jurisdictional portion of amortizations, approved by the Commission, that were recorded during the applicable twelve-month ended period converted to revenue requirements.

9. “i” is the actual jurisdictional portion of net renewable energy credit (“REC”) proceeds from any sales during the applicable twelve-month ended period converted to revenue requirements.

10. “j” is the individual retail rate group’s adjusted billing cycle kilowatt-hour sales for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the HLF customer group such that “k” shall be the sum of kilowatts billed for the same twelve-month period.

The factor shall be further modified to reflect the difference between estimated operating costs billed and operating costs actually incurred for those costs that are recovered on a projected basis and to reflect the difference between operating costs and credits actually incurred, including return revenue requirements, operating costs, credits, and return collected from customers for operating costs and credits that are recovered on an actual basis.

The Renewable Energy Project Adjustment factor applicable to retail rate groups shall be as follows: