FILED
August 28, 2024
INDIANA UTILITY
REGULATORY COMMISSION

OFFICIAL
EXHIBITS

DIRECT TESTIMONY OF ART J. BUESCHER, III
LEAD RATES AND REGULATORY STRATEGY ANALYST
DUKE ENERGY INDIANA, LLC
CAUSE NO. 42736 RTO-60
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

IURC
PETITIONER'S
EXHIBIT NO. 1
11-4-24 AT
DATE REPORTER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Art J. Buescher, III 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," "Petitioner" or "Company") as Lead Rates and Regulatory Strategy Analyst in Duke Energy Indiana's Rate Department.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN THE INDIANA RATE DEPARTMENT?

A. As Lead Rates and Regulatory Strategy Analyst, I am responsible for the preparation of financial and accounting data used in Duke Energy's rate filings, including rate matters involving Duke Energy Indiana.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I graduated from of the University of Indianapolis in May of 1988 with a Bachelor of Science Degree in Accounting. I was employed by the Company in June 1988. During my employment with the Company, 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 2007, I held various financial and accounting positions in Cost Accounting, Internal Auditing, Energy Trading Accounting, and as Supervisor, Fuels and Joint Ownership Accounting.

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

A. My testimony in this proceeding supports the Company's request for approval of the proposed Rider No. 68 adjustment factors for the Company's Standard Contract Rider No. 68 ("Rider No. 68" or "RTO"), which includes a new projection as well as a reconciliation for prior historical periods.

Q. WHAT MONTHS OF HISTORICAL COSTS AND TRANSMISSION REVENUES ARE COVERED BY THE COMPANY'S PETITION IN THIS PROCEEDING?

A. The applicable non-fuel costs and transmission revenues for the reconciliation period of July 2023 through June 2024 are included in this proceeding.

Q. WHAT MONTHS OF PROJECTED COSTS AND TRANSMISSION REVENUES ARE COVERED BY THE COMPANY'S PETITION IN THIS PROCEEDING?

A. The forecasted amounts for applicable costs and transmission revenues are included for the months of January 2025 through December 2025.

II. BACKGROUND

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMPANY'S RETAIL BASE RATE ORDERS RELEVANT TO THE COMPANY'S RIDER NO. 68.

A. In its May 18, 2004 Order in Cause No. 42359, the Commission first approved Rider No. 68 to track recovery from (or credit to) the Company's retail electric customers certain Company charges, credits and transmission revenues related to MISO. In the June 29, 2020 Order in Cause No. 45253, the Company's most recent retail base rate case, the Commission approved Rider No. 68 to continue and to include, on a prospective basis, non-fuel charges and credits assessed from PJM Interconnection, LLC ("PJM"), as it relates to the Company's Madison Generating Station as further described in the prefiled testimony of Mr. John D. Swez in this proceeding.

Q. ARE THERE OTHER KEY COMMISSION ORDERS THAT PROVIDE IMPORTANT BACKGROUND ON THE DEVELOPMENT OF THE COMPANY'S RIDER NO. 68?

A. Yes. There are a few Commission Orders that have had a significant impact on the development of this rider. In the Commission's June 1, 2005 Order in Cause No. 42685 ("June 1, 2005 Order") the Commission addressed MISO's implementation of the Energy Markets. Specifically with respect to the Company, the June 1, 2005 Order determined that certain Duke Energy Indiana's Energy Markets charges (and credits) were fuel-related and should therefore be reflected in the Company's subsequent Fuel Cost Adjustment Standard Contract Rider No. 60 proceedings. The Order also found that Rider No. 68 should continue to provide for the Company's non-fuel related MISO cost recovery under Energy Markets operations.

The Commission later approved, in its December 19, 2007 Order in Cause No. 42736 RTO-12, the recovery of Schedule 26 ("Network Upgrade Charge from Transmission Expansion Plan") costs assessed the Company by MISO as part of the Regional Expansion and Criteria and Benefits ("RECB") process through Rider No. 68, whether those costs are associated with transmission projects of other transmission owners or whether those costs are associated with the Company's RECB projects. Furthermore in the June 25, 2008 Order in Cause No. 42736 RTO-14, the Commission approved the Company's proposal for recovery of RECB Schedule 26 charges on Company-owned, MISO approved RECB transmission projects. Later in my testimony I provide further discussion on the regulatory treatment of the Company's RECB projects and Attachment 1-G (AJB) provides information on these Company-owned, MISO approved RECB projects, including estimates of Schedule 26 costs.

In the Commission's September 24, 2008 Order in Cause No. 42736 RTO-15 and the Commission's June 30, 2009 Order in Cause No. 42736 RTO-18, the Commission approved the Company's recovery of charges and credits associated with its participation in the MISO Ancillary Services Market ("ASM"). Specifically, the Company began including the following ASM charge types in its

Rider No. 68 filings: (a) the Real Time Revenue Neutrality Uplift Amount exclusive of the credits associated with the Contingency Reserve Deployment Failure Uplift Amount; (b) the Day Ahead Market Administration Amount; and (c) the Real Time Market Administration Amount. In its June 27, 2012 Order in Cause No. 42736 RTO-30, the Commission approved the recovery of Schedule 26-A ("Multi-Value Project Usage Rate" or "MVP") costs allocated to the Company by MISO for projects of other transmission owners through Rider No. 68, whether those costs are associated with transmission projects of other transmission owners. Later in my testimony, I provide further discussion on the regulatory treatment of the Company's MVP projects. Attachment 1-H (AJB) provides information on these Company-owned, MISO approved MVP projects, including estimates of Schedule 26-A costs.

In the Commission's September 24, 2014 Order in Cause No. 42736 RTO-39, the Commission determined that the Real-Time MVP Distribution charge type assessed by MISO was properly includable in Rider No. 68. In the February 24, 2021 Order in Cause No. 42736 RTO-56, the Commission approved the recovery of Schedule 26-C (Cost Recovery For MISO Transmission Owner TEMPS), Schedule 26-D (Cost Recovery For PJM Transmission Owner TEMPS) and Schedule 49 (Cost Allocation For Available System Capacity Usage) costs allocated to the Company through Rider No. 68. In its December 7, 2022 Order in Cause No. 42736 RTO-58, the Commission authorized the Company to recover

MISO Schedule 26-E (Cost Recovery for MISO Transmission Owner IMEPS) under the MISO Tariff in its Rider No. 68 proceedings.

Q. ARE THERE COMPANY-OWNED RECB PROJECTS IN THIS FILING FOR WHICH THE COMPANY IS SEEKING RECOVERY?

A. Yes, the Company has three (3) RECB projects in service as follows: (a) the first phase of a baseline reliability transmission line project spanning approximately four (4) miles and referred to by MISO as Project Number 852 completed in 2009 and the final phase spanning seventeen (17) miles completed in 2013; (b) the Edwardsport 345 kV substation and line project referred to by MISO as Project Number 1263 completed in 2010; and (c) the Dresser substation and transformer project referred to by MISO as Project Number 2050 completed in 2011. In June of 2024, the Company submitted to MISO its revised annual revenue requirement for these projects for changes in the approved return on equity ("ROE"), which totaled $2,506,630, and the Company, as a transmission owner, began receiving updated revenues July 1, 2024. These RECB projects are listed on Attachment 1-G (AJB). The Company, as a transmission customer, also pays MISO its share of the corresponding Schedule 26 costs.

Q. ARE THERE COMPANY-OWNED MVP PROJECTS IN THIS FILING FOR WHICH THE COMPANY IS SEEKING RECOVERY?

A. Yes, the Company has two (2) MISO MVP projects. These two (2) projects consist of three (3) facilities which are comprised of eight (8) separate detail projects. The first detail project went in service May 2018, three (3) went in service June 2018, one (1) went in service June 2019, and one (1) went in service September 2019. The remaining two (2) detail projects were in service by December 2020. The three (3) facilities are as follows:

- MTEP Project ID 2237 is the Sugar Creek to Kansas 345 kV line project known as MISO Facility ID 8313, which consists of four (4) detail projects of which two (2) were in service at the end of 2019 and the final two (2) detail projects were in service by December 2020;
- MTEP Project ID 2202 is the Reconductor Wabash to Wabash Container Section project known as Facility ID 7286, which consists of two (2) detail projects of which both were in service as of June 2018.
- MTEP Project ID 2202 is the Kokomo Delco to Greentown 138 kV Uprate project known as MISO Facility 7287, which consists of two (2) detail projects with the first in service May 2018 and the second in service June 2018.

In June of 2024, the Company submitted to MISO its revised annual revenue requirement for these projects for changes in the approved ROE, which totaled $1,622,721, and the Company, as a transmission owner, began receiving revenues July 1, 2024. These MVP projects are listed on Attachment 1-H (AJB).

Q. HAS THE COMPANY EXCLUDED THE REVENUE RELATED TO THESE RECB AND MVP PROJECTS FROM THIS FILING?

A. Yes, the Company has retained this revenue, as previously ordered by the Commission, and Rider No. 68 costs were not offset by the revenue from these projects.

Q. HAS THE COMPANY EXCLUDED THE REVENUES AND EXPENSES RELATED TO THESE PROJECTS FROM THE FAC EARNINGS TEST?

A. Yes, the Company has excluded the applicable revenues and expenses related to its own RECB and MVP Projects from the FAC Earnings Test. See the direct testimony of Company witness Christa L. Graft in Cause No. 38707 FAC-141, which discusses the adjustments to the Company's Earnings Test to exclude revenues and expenses associated with its own RECB and MVP projects.

III. <u>OVERVIEW OF RIDER NO. 68</u>

Q. PLEASE BRIEFLY DESCRIBE THE NON-FUEL CHARGES AND CREDITS AND TRANSMISSION REVENUES COVERED BY RIDER NO. 68.

A. Under Rider No. 68, the Company will track for recovery from (or credit to) the Company's retail electric customers the following:

- MISO management costs billed to the Company by MISO under Schedules 10 (ISO Cost Recovery Adder) and 10-FERC (FERC Annual Charges Recovery);

- MISO management costs billed to the Company by MISO under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder);
- MISO management costs billed to the Company by MISO under Schedule 17 (Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder);
- Costs billed to the Company by MISO under the MISO Tariff for standard market design which is allocable to the Company's retail electric customers (including charges under Schedule 26, Schedule 26-A, Schedule 26-C, Schedule 26-D, Schedule 26-E, Schedule 49, Real-Time Revenue Neutrality Uplift, Real Time Miscellaneous Amount and Real-Time MVP Distribution Amount);
- Other government mandated transmission costs the Company is required to pay on behalf of its retail electric customers;
- Certain MISO transmission revenues assigned to the Company, collected by MISO under the MISO Tariff, which are allocable to the Company's retail electric customers; and
- Costs billed to the Company by PJM under the PJM Tariff for non-fuel charges or credits applicable to the Company's Ohio-based Madison Generating Station designated as an Indiana resource in MISO (including PJM Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control, and Black Start Service).

Q. HAVE ANY NEW NON-FUEL MISO CHARGES OR CREDITS BEEN INCLUDED IN EITHER THE FORECASTED OR RECONCILIATION PERIOD?

A. No.

Q. PLEASE BRIEFLY DESCRIBE HOW THE FORECASTED MISO COSTS AND TRANSMISSION REVENUES WERE DETERMINED.

A. For purposes of forecasting the Schedule 26 and 26-A charges, the Company started with projected data available from MISO to reflect the charges by other market participants that will be applicable to Duke Energy Indiana. For the remaining charges, credits and revenues, the forecasted amounts were based on a twenty-four (24) month history of these items and then were adjusted for any known or anticipated changes. As the Company becomes more experienced with forecasting these costs, the methods utilized may evolve over time.

Q. PLEASE BRIEFLY DESCRIBE THE RECONCILIATION STEP IN THE RIDER NO. 68 PROCESS.

A. There is a reconciliation step included in the Rider No. 68 process to adjust for (a) any variances between the Company's projected RTO costs and transmission revenues versus actual RTO costs and transmission revenues incurred and (b) variances between the previous RTO tracker amounts by retail rate group authorized for recovery versus the actual RTO revenues collected by retail rate group. The reconciliation in the current proceeding includes the months of July

2023 through June 2024 and is shown in Columns C and D of Attachment 1-B (AJB).

Q. PLEASE BRIEFLY DESCRIBE ANY SPECIAL PROVISIONS FOR COMMISSION APPROVAL OF COSTS COVERED BY RIDER NO. 68, WHICH ARE NOT BILLED BY MISO OR PJM PURSUANT TO THE SPECIFIC APPROVED SCHEDULES.

A. To the extent that any costs to be recovered pursuant to Rider No. 68 are not billed by MISO or PJM to the Company (or a designee of the Company) pursuant to the specifically approved Schedules of the MISO or PJM Tariff, or any successor Tariff, the Company will demonstrate in its applicable annual filing the amount and reasonableness of such costs. No such costs were included in the current filing.

Q. PLEASE BRIEFLY EXPLAIN HOW COSTS OR TRANSMISSION REVENUES THAT ARE NOT ACCOUNTED FOR SEPARATELY FOR THE COMPANY'S RETAIL ELECTRIC CUSTOMERS WILL BE HANDLED UNDER RIDER NO. 68.

A. To the extent that the costs or transmission revenues identified in the formula set forth in the Rider No. 68 Tariff are not accounted for separately for the Company's retail electric customers, then the total Company amount of such costs or transmission revenues, whichever is applicable, will be multiplied by the Commission-approved retail allocator for the applicable period to determine the retail electric jurisdictional portion of such costs or transmission revenues. In Cause No. 45253, the retail allocator for transmission is 100%.

Q. WHAT REVENUE CONVERSION FACTOR IS BEING USED FOR RIDER NO. 68 IN THIS PROCEEDING?

A. The revenue conversion factor used for this proceeding is 1.00432. See Attachment 1-I (AJB) for the underlying calculation of this factor.

IV. PROPOSED RIDER NO. 68 ADJUSTMENT FACTORS

Q. PLEASE EXPLAIN ATTACHMENT 1-A (AJB).

A. Attachment 1-A (AJB) is the Company's proposed revised tariff for Standard Contract Rider No. 68.

Q. HAVE YOU CALCULATED THE PROPOSED RIDER 68 ADJUSTMENT BILLING FACTORS FOR THE VARIOUS RETAIL RATE GROUPS USING THE COST COMPONENTS AND AMOUNTS YOU HAVE DESCRIBED?

A. Yes, I have. Attachment 1-B (AJB) includes projected RTO costs and transmission revenues (Column B) above what is included in base rates and a reconciliation of prior historical amounts (Columns C and D) broken down by retail rate group for those specific MISO and PJM cost components I have discussed in my testimony that were previously approved by the Commission for inclusion in Rider No. 68 rates via the current RTO proceeding. The resulting revenue requirement totals for each retail rate group (except for HLF) (Column E) are divided by the corresponding kWh sales for the twelve (12)-months ended

June 30, 2024. For developing the HLF rate, the revenue requirement amount is divided by KW demands for the twelve (12)-months ended June 30, 2024 to determine the proposed Rider No. 68 rate. These factors by respective retail rate groups are then reflected on Page 3 of 3 of Attachment 1-A (AJB). The total amount that the Company proposes to be credited to the Company's retail electric customers through Rider No. 68, taking into account the reconciliation amount, is $2,142,696.

The prefiled testimony of Mr. John D. Swez, Attachment 2-A (JBD), supports the reasonableness of the Company's MISO Energy Markets and ASM and PJM non-fuel related charges and credits.

Q. ARE YOU AWARE OF ANY MATERIAL SETTLEMENTS TO ANY RTO NON-FUEL CHARGES OR CREDITS INCLUDED IN THIS PROCEEDING?

A. Yes. As the result of the January 4, 2024 FERC Order in Docket No. IN24-3-000, MISO was required to return amounts disgorged to MISO from Linde and NIPSCO to the Load Serving Entities and other Market Participants that were charged by MISO as settlement to FERC's investigation related to MISO's Demand Response Resource – Type 1 market.

Duke Energy Indiana received approximately $2.9 million from MISO as part of this settlement through the Real Time Miscellaneous charge type. This credit to customers has been included in Petitioner's Exhibit 1-D (AJB).

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO BRING TO THE COMMISSION'S ATTENTION?

A. Yes. In July 2022, MISO's Board of Directors approved Tranche 1 of their Long-Range Transmission Plan (LRTP) which is a comprehensive strategy to address the growing demands of the electric grid across its service region. This first phase includes 18 transmission projects with a $10.3 billion investment focused on the Midwest Subregion to improve grid reliability and support integration of renewable energy sources. The Company will be allocated a share of the costs for these projects by MISO under Schedule 26-A.

A second phase, Tranche 2, also focuses on the Midwest region and includes a larger scope with estimated costs of $25 billion. Tranche 2 is expected to receive MISO Board of Director's approval by the end of 2024.

As these projects begin construction and the associated costs begin to flow through the MISO Schedule 26-A tariff, the Company expects to see significant increases in the amount of costs allocated by MISO for the LRTP projects and ultimately included for recovery in the Company's Rider 68 proceedings.

Q. HAS THE COMPANY INCLUDED ANY ESTIMATES FOR THE FUTURE LRTP COSTS IN THIS PROCEEDING?

A. No. The forecasted period in this Rider 68 proceeding only covers the January 2025 thru December 2025 period. As more information on these LRTP projects become available the Company will update its forecast to include the most accurate representation of costs in future proceedings.

Q. WAS THERE ANY SINGLE ADJUSTMENT IN EXCESS OF $3 MILLION INCLUDED IN THIS PROCEEDING?[1]

A. No.

Q. PLEASE EXPLAIN ATTACHMENT 1-C (AJB).

A. Attachment 1-C (AJB) compares the forecasted non-fuel RTO costs and transmission revenues for the forecasted periods of January 2025 through December 2025 to the Company's annual charges built into base retail electric rates in Cause No. 45253. The total to be recovered from (or credited to) customers is shown on Attachment 1-B (AJB), Column (B).

Q. PLEASE EXPLAIN ATTACHMENT 1-D (AJB).

A. Attachment 1-D (AJB) compares the previously projected RTO non-fuel costs and transmission revenues (developed in RTO 58 and 59) to actual non-fuel costs and transmission revenues incurred during the reconciliation period of July 2023 through June 2024. The total to be recovered from (or credited to) customers from this portion of the reconciliation is shown on Attachment 1-B (AJB), Column (C).

Q. PLEASE EXPLAIN ATTACHMENT 1-E (AJB).

A. Attachment 1-E (AJB) compares the actual amount of Rider No. 68 amounts charged (or credited) to customers at the retail rate group level to the amounts approved by the Commission for recovery during the reconciliation periods of

[1] In Cause No. 42736 RTO-13, the Company defined the term "single adjustment" as an adjustment that is unique and/or non-recurring and outside the routine settlement and Post Analysis Cost Evaluator ("PACE") process described in testimony in the Company's FAC proceedings (Petitioner's Attachment A, p. 23). Since 2015, the PACE process is administered by the Sumatra model.

July 2023 through June 2024. The total to be recovered from (or credited to) customers for this item is shown on Attachment 1-B (AJB), Column (D).

Q. PLEASE EXPLAIN ATTACHMENT 1-F (AJB).

A. Attachment 1-F (AJB) compares the bill of a typical residential customer using 1000 kilowatt-hours per month based upon the proposed Rider No. 68 adjustment factor to the bill of a typical residential customer using 1000 kilowatt-hours per month based upon the most recently approved rate. Under the proposed Rider No. 68 adjustment, a typical residential customer will experience an increase on his or her electric bill of \$0.23 or 0.18% when compared to the bills reflecting the current Rider No. 68 rate.

Q. PLEASE EXPLAIN ATTACHMENT 1-G (AJB).

A. Attachment 1-G (AJB) provides information relating to Company-owned, MISO-approved RECB projects and provides an estimate of Schedule 26 costs to be allocated to the Company based on information provided by MISO.

Q. PLEASE EXPLAIN ATTACHMENT 1-H (AJB).

A. Attachment 1-H (AJB) provides information relating to Company-owned, MISO-approved MVP projects and provides an estimate of Schedule 26-A costs to be allocated to the Company based on information provided by MISO.

Q. PLEASE EXPLAIN ATTACHMENT 1-I (AJB).

A. Attachment 1-I (AJB) shows the calculation of the revenue conversion factor being used in this proceeding.

Q. PLEASE EXPLAIN ATTACHMENTS 1-J (AJB) AND 1-K (AJB).

A. The standard format for Duke Energy Indiana filings (labeled as Attachment 1-J (AJB) in this proceeding) and the Workpaper Listing (labeled as Attachment 1-K (AJB) in this proceeding) were updated to reflect my Testimony and Workpapers.

V. CONCLUSION

Q. WHAT REVISIONS TO THE COMPANY'S RETAIL ELECTRIC TARIFF ARE BEING PROPOSED TO REFLECT THE RIDER NO. 68 TREATMENT PROPOSED IN THIS PROCEEDING?

A. The Company is proposing to revise its current Standard Contract Rider No. 68, Fourth Revised Sheet No. 68, Page 1 through Page 3, as reflected in Attachment 1-A (AJB), Pages 1 through 3. The Company requests that the Commission find that the Rider No. 68 adjustment factors for the Company's bills rendered beginning with the January 2025 – Cycle 1 billing cycle, or the date of the Commission's Order if later, for the Company's retail electric customers should be as set forth on page 3 of Attachment 1-A (AJB).

Q. WERE ATTACHMENTS 1-A (AJB) THROUGH 1-K (AJB) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

DUKE ENERGY INDIANA, LLC
1000 E. Main Street
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STANDARD CONTRACT RIDER 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 ($59,998,000).

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

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 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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IURC No. 15
Sixth Revised Sheet No. 68
Cancels and Supersedes
Fifth Revised Sheet No. 68

STANDARD CONTRACT RIDER NO. 68 -
REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

ALLOCATED SHARE OF SYSTEM PEAK DEMAND FOR RETAIL CUSTOMERS BY RATE GROUP EXPRESSED AS A PERCENTAGE OF THE COMPANY'S TOTAL RETAIL SYSTEM PEAK DEMAND AS DEVELOPED FOR COST OF SERVICE PURPOSES IN CAUSE NO. 45253

Line No.	Rate Groups	KW Share of System Peak (4CP) Per Cause No. 45253 (A)	Percent Share Of System Peak (B)	Line No.
1	Rate RS	2,102,591	42.114%	1
2	Rates CS and FOC	258,053	5.169%	2
3	Rate LLF	1,034,546	20.722%	3
4	Rate HLF	1,536,449	30.774%	4
5	Customer L	14,800	0.296%	5
6	Customer O	18,584	0.372%	6
7	Rate WP	20,717	0.415%	7
8	Rate SL	79	0.002%	8
9	Rate MHLS	15	0.000%	9
10	Rates MOLS and UOLS	5,633	0.113%	10
11	Rates TS, FS and MS	1,141	0.023%	11
12	TOTAL RETAIL	4,992,608	100.000%	12

Issued: Pending **Effective:**

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IURC No. 15
Sixth Revised Sheet No. 68
Cancels and Supersedes
Fifth Revised Sheet No. 68

STANDARD CONTRACT RIDER NO. 68 -
REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

Line No.	Retail Rate Group	RTO Non-Fuel Cost and Revenue Adjustment Factor Per KWH (A)	RTO Non-Fuel Cost and Revenue Adjustment Factor Per Non-Coincident KW (B)	Line No.
1	Rate RS	($0.000091)		1
2	Rates CS and FOC	(0.000060)		2
3	Rate LLF	(0.000091)		3
4	Rate HLF		($0.044600)	4
5	Customer L	0.000024		5
6	Customer O	(0.000069)		6
7	Rate WP	(0.000059)		7
8	Rate SL	(0.000001)		8
9	Rate MHLS	0.000000		9
10	Rates MOLS and UOLS	(0.000023)		10
11	Rates TS, FS and MS	(0.000079)		11

Issued: Pending

Effective:

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COST AND REVENUE ADJUSTMENT FACTORS BY RATE GROUP
TO BE APPLIED TO CUSTOMER BILLS OVER A TWELVE MONTH PERIOD

Line No.	Retail Rate Group Description	Allocated Percentage Share of Retail Peak Demands for the Company's Retail Electric Customers Approved in IURC Cause No. 45253	Projected RTO Non-Fuel Costs and Revenues By Rate Group for Calendar Year 2025 to be Collected through Standard Contract Rider No. 68 _1/	Reconciliation of Amounts Projected for RTO Non-Fuel Costs and Revenues vs. Actual Amounts Incurred for the July 2023 through June 2024 Period	Reconciliation of RTO Non-Fuel Costs and Revenues Approved for Recovery vs. Actual RTO Revenues Collected for the July 2023 through June 2023 Period	Total	Actual Kilowatt-Hour Sales For The Twelve Months Ended June 30, 2024	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Kilowatt-Hour By Rate Group	Actual Sum of Monthly Non-Coincident Peak Demands for the Twelve Months Ended June 30, 2024	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Non-Coincident Peak Demands	Line No.
		(A)	(B)	(C)	(D)	(E) (B)+(C)+(D)+(E)	(F)	(G)	(H)	(I)	
1	Rate RS	42.114%	$ 1,620,357	$ (2,525,154)	$ 103,662	$ (801,135)	8,800,191,305	($0.000091)			1
2	Rates CS	5.169%	198,880	(309,933)	47,287	(63,766)	1,054,456,213	($0.000060)			2
3	Rate LLF	20.722%	797,289	(1,242,490)	(46,390)	(491,591)	5,403,846,164	($0.000091)			3
4	Rate HLF	30.774%	1,184,045	(1,845,208)	(104,628)	(765,791)	8,900,376,945		17,170,018	($0.044600)	4
5	Customer L	0.296%	11,389	(17,748)	8,920	2,561	108,464,956	$0.000024			5
6	Customer O	0.372%	14,313	(22,305)	(2,983)	(10,975)	157,943,547	($0.000069)			6
7	Rate WP	0.415%	15,967	(24,883)	(355)	(9,271)	157,583,756	($0.000059)			7
8	Rate SL	0.002%	77	(120)	24	(19)	29,006,431	($0.000001)			8
9	Rate MHLS	0.000%	-	-	(2)	(2)	4,376,575	$0.000000			9
10	Rates MOLS and UOLS	0.113%	4,348	(6,775)	241	(2,186)	94,960,814	($0.000023)			10
11	Rates TS, FS and MS	0.023%	885	(1,379)	(27)	(521)	6,566,072	($0.000079)			11
12	**TOTAL RETAIL**	100.000%	$ 3,847,550	$ (5,995,996)	$ 5,749	$ (2,142,696)	24,717,772,778				12

_1/ The retail allocation percentages in Column (A) were used to calculate the amounts per Retail Rate Group for the projection of non-fuel costs and transmission revenues shown on Line 12 in Column (B) and Column (C).

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE FORECASTED REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUES
TO BE RECOVERED OR CREDITED THROUGH RIDER 68 FOR THE TWELVE MONTHS ENDED DECEMBER 2025

Line No.	Description	January 2025	February 2025	March 2025	April 2025	May 2025	June 2025	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M) SUM (A) - (L)	
	Forecasted RTO Non-Fuel Costs & Transmission Revenues														
	Non-Fuel Costs														
1	Schedule 10 FERC	186,500	186,500	186,500	186,500	186,500	186,500	186,500	186,500	186,500	186,500	186,500	186,500	2,238,000	1
2	Schedule 10	480,833	480,833	480,834	480,833	480,833	480,834	480,833	480,833	480,834	480,833	480,833	480,834	5,770,000	2
3	Schedule 16	12,667	12,667	12,666	12,667	12,667	12,666	12,667	12,667	12,666	12,667	12,667	12,666	152,000	3
4	Schedule 17	432,083	432,083	432,084	432,083	432,083	432,084	432,083	432,083	432,084	432,083	432,083	432,084	5,185,000	4
5	Real Time Miscellaneous	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	1,000,000	5
6	Real Time Revenue Neutrality Uplift Amount	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	7,200,000	6
7	Real Time MVP Distribution Amount	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(1,000,000)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	738,333	738,333	738,334	738,333	738,333	738,334	738,333	738,333	738,334	738,333	738,333	738,334	8,860,000	8
9	Schedule 26 A - Multi-Value Projects	3,963,333	3,963,333	3,963,334	3,963,333	3,963,333	3,963,334	3,963,333	3,963,333	3,963,334	3,963,333	3,963,333	3,963,334	47,560,000	9
10	Schedule 26 C	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	336,000	10
11	Schedule 26 D	833	833	834	833	833	834	833	833	834	833	833	834	10,000	11
12	Schedule 26 E	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	78,000	12
13	Schedule 49	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	1,100,000	13
14	PJM Madison Non-Fuel	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,800,000	14
15	Total RTO Non-Fuel Costs	6,690,749	6,690,749	6,690,752	6,690,749	6,690,749	6,690,752	6,690,749	6,690,749	6,690,752	6,690,749	6,690,749	6,690,752	80,289,000	15
16	*Transmission Revenues*	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(40,000,000)	16
17	Total Non-Fuel Costs & Transmission Revenues	3,357,416	3,357,416	3,357,418	3,357,416	3,357,416	3,357,418	3,357,416	3,357,416	3,357,418	3,357,416	3,357,416	3,357,418	40,289,000	17
	Amounts Included in Base Rates														
	Non-Fuel Costs														
18	Schedule 10 FERC	211,583	211,583	211,584	211,583	211,583	211,584	211,583	211,583	211,584	211,583	211,583	211,584	2,539,000	18
19	Schedule 10	482,417	482,417	482,416	482,417	482,417	482,416	482,417	482,417	482,416	482,417	482,417	482,416	5,789,000	19
20	Schedule 16	26,917	26,917	26,916	26,917	26,917	26,916	26,917	26,917	26,916	26,917	26,917	26,916	323,000	20
21	Schedule 17	528,333	528,333	528,334	528,333	528,333	528,334	528,333	528,333	528,334	528,333	528,333	528,334	6,340,000	21
22	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	22
23	Real Time Revenue Neutrality Uplift Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	23
24	Real Time MVP Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	24
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	673,583	673,583	673,584	673,583	673,583	673,584	673,583	673,583	673,584	673,583	673,583	673,584	8,083,000	25
26	Schedule 26 A - Multi-Value Projects	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	36,924,000	26
27	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	27
28	Schedule 26 D	-	-	-	-	-	-	-	-	-	-	-	-	-	28
29	Schedule 26 E	-	-	-	-	-	-	-	-	-	-	-	-	-	29
30	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	30
31	PJM Madison Non-Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	31
32	Total RTO Non-Fuel Costs	4,999,833	4,999,833	4,999,834	4,999,833	4,999,833	4,999,834	4,999,833	4,999,833	4,999,834	4,999,833	4,999,833	4,999,834	59,998,000	32
33	*Transmission Revenues*	(1,961,667)	(1,961,667)	(1,961,666)	(1,961,667)	(1,961,667)	(1,961,666)	(1,961,667)	(1,961,667)	(1,961,666)	(1,961,667)	(1,961,667)	(1,961,666)	(23,540,000)	33
34	Total Non-Fuel Costs & Transmission Revenues	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	36,458,000	34
	Net Forecasted RTO Non-Fuel Costs & Transmission Revenues														
	Non-Fuel Costs														
35	Schedule 10 FERC	(25,083)	(25,083)	(25,084)	(25,083)	(25,083)	(25,084)	(25,083)	(25,083)	(25,084)	(25,083)	(25,083)	(25,084)	(301,000)	35
36	Schedule 10	(1,584)	(1,584)	(1,582)	(1,584)	(1,584)	(1,582)	(1,584)	(1,584)	(1,582)	(1,584)	(1,584)	(1,582)	(19,000)	36
37	Schedule 16	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(14,250)	(171,000)	37
38	Schedule 17	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(96,250)	(1,155,000)	38
39	Real Time Miscellaneous	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	1,000,000	39
40	Real Time Revenue Neutrality Uplift Amount	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	7,200,000	40
41	Real Time MVP Distribution Amount	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(1,000,000)	41
42	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	64,750	64,750	64,750	64,750	64,750	64,750	64,750	64,750	64,750	64,750	64,750	64,750	777,000	42
43	Schedule 26 A - Multi-Value Projects	886,333	886,333	886,334	886,333	886,333	886,334	886,333	886,333	886,334	886,333	886,333	886,334	10,636,000	43
44	Schedule 26 C	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	336,000	44
45	Schedule 26 D	833	833	834	833	833	834	833	833	834	833	833	834	10,000	45
46	Schedule 26 E	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	78,000	46
47	Schedule 49	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	1,100,000	47
48	PJM Madison Non-Fuel	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,800,000	48
49	Total RTO Non-Fuel Costs	1,690,916	1,690,916	1,690,918	1,690,916	1,690,916	1,690,918	1,690,916	1,690,916	1,690,918	1,690,916	1,690,916	1,690,918	20,291,000	49
50	*Transmission Revenues*	(1,371,666)	(1,371,666)	(1,371,668)	(1,371,666)	(1,371,666)	(1,371,668)	(1,371,666)	(1,371,666)	(1,371,668)	(1,371,666)	(1,371,666)	(1,371,668)	(16,460,000)	50
51	Total Non-Fuel Costs & Transmission Revenues	319,250	319,250	319,250	319,250	319,250	319,250	319,250	319,250	319,250	319,250	319,250	319,250	3,831,000	51
52	Revenue Conversion Factor													1.00432	52
53	Amount to be Collected (Credited) Through Rider													3,847,550	53

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF AMOUNTS FORECASTED FOR REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUES
VERSUS ACTUAL AMOUNTS INCURRED FOR THE JULY 2023 THROUGH JUNE 2024 PERIOD

		RTO 58							RTO 59								
Line No.	Description	July 2023	August 2023	September 2023	October 2023	November 2023	December 2023	Sub-Total	January 2024	February 2024	March 2024	April 2024	May 2024	June 2024	Sub-Total	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	
								Sum (A) to (F)							Sum (H) to (M)	(G)+(N)	
	Actual RTO Non-Fuel Costs & Transmission Revenues																
	Non-Fuel Costs																
1	Schedule 10 FERC	207,906	230,970	304,375	276,736	242,929	232,792	1,495,708	240,329	306,888	212,642	221,942	201,484	258,681	1,441,966	2,937,674	1
2	Schedule 10	405,503	431,307	536,339	428,412	451,964	271,865	2,525,390	217,311	589,220	371,478	493,154	594,851	458,578	2,724,592	5,249,982	2
3	Schedule 16	11,664	11,013	8,573	8,480	7,950	11,333	59,013	10,005	12,601	8,903	6,520	6,955	8,450	53,434	112,447	3
4	Schedule 17	444,972	456,949	336,812	482,143	402,404	385,104	2,508,384	387,172	379,068	348,500	425,772	442,895	426,212	2,409,619	4,918,003	4
5	Real Time Miscellaneous	(170,427)	(1,802)	(451,085)	59,037	-	(13,988)	(578,265)	8,792	(2,874,619)	7,708	(27,970)	1,153	7,591	(2,877,345)	(3,455,610)	5
6	Real Time Revenue Neutrality Uplift Amount	361,252	757,202	1,161,212	654,856	1,193,915	602,774	4,731,211	1,195,587	460,526	614,383	436,720	509,156	718,617	3,934,989	8,666,200	6
7	Real Time MVP Distribution Amount	(5,480)	(5,552)	(6,912)	(18,766)	(17,998)	(18,837)	(73,545)	(145,326)	(155,089)	(153,164)	(124,643)	(125,141)	(124,544)	(827,907)	(901,452)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	686,358	760,241	824,943	750,416	655,329	634,338	4,311,625	653,416	798,536	553,629	577,274	520,320	669,081	3,772,256	8,083,881	8
9	Schedule 26 A - Multi-Value Projects	3,611,946	4,138,241	4,093,581	3,403,563	3,123,537	3,358,311	21,729,179	3,795,820	4,399,090	3,795,166	3,994,507	3,555,754	3,826,002	23,366,339	45,095,518	9
10	Schedule 26 C	28,441	27,520	27,813	28,921	28,797	28,564	170,056	28,813	29,341	28,290	28,585	28,945	28,160	172,134	342,190	10
11	Schedule 26 D	638	617	640	648	647	639	3,829	645	416	401	404	410	396	2,672	6,501	11
12	Schedule 26 E	6,670	6,438	6,683	6,768	6,734	6,695	39,988	6,750	6,546	6,312	6,375	6,445	6,271	38,699	78,687	12
13	Schedule 49	111,054	87,755	116,148	110,808	119,172	114,624	659,561	111,891	110,324	116,405	1,678	112,962	130,000	583,260	1,242,821	13
14	PJM Madison Non-Fuel	162,911	177,262	169,958	149,355	153,612	134,751	947,849	141,695	140,408	119,631	149,941	148,588	154,895	855,158	1,803,007	14
15	Total RTO Non-Fuel Costs	5,863,408	7,078,161	7,129,080	6,341,377	6,368,992	5,748,965	38,529,983	6,652,900	4,203,256	6,030,284	6,190,259	6,004,777	6,568,390	35,649,866	74,179,849	15
16	*Transmission Revenues*	(4,249,960)	(4,581,538)	(2,822,985)	(2,713,717)	(3,110,999)	(3,581,275)	(21,060,474)	(3,801,856)	(2,604,746)	(3,121,557)	(2,481,188)	(3,174,150)	(4,859,083)	(20,042,580)	(41,103,054)	16
17	Total Non-Fuel Costs & Transmission Revenues	1,613,448	2,496,623	4,306,095	3,627,660	3,257,993	2,167,690	17,469,509	2,851,044	1,598,510	2,908,727	3,709,071	2,830,627	1,709,307	15,607,286	33,076,795	17
18	Less: Amount in Base Rates	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	36,458,000	18
19	Net Total Actual	(1,424,718)	(541,543)	1,267,927	589,494	219,827	(870,478)	(759,491)	(187,122)	(1,439,656)	(129,441)	670,905	(207,539)	(1,328,861)	(2,621,714)	(3,381,205)	19
	Forecasted RTO Non-Fuel Costs & Transmission Revenues																
	Non-Fuel Costs																
20	Schedule 10 FERC	216,666	216,667	216,667	216,666	216,667	216,667	1,300,000	216,667	216,667	216,666	216,667	216,667	216,666	1,300,000	2,600,000	20
21	Schedule 10	500,000	500,000	500,000	500,000	500,000	500,000	3,000,000	500,000	500,000	500,000	500,000	500,000	500,000	3,000,000	6,000,000	21
22	Schedule 16	12,500	12,500	12,500	12,500	12,500	12,500	75,000	12,500	12,500	12,500	12,500	12,500	12,500	75,000	150,000	22
23	Schedule 17	391,666	391,667	391,667	391,666	391,667	391,667	2,350,000	391,667	391,667	391,666	391,667	391,667	391,666	2,350,000	4,700,000	23
24	Real Time Miscellaneous	83,333	83,333	83,334	83,333	83,333	83,334	500,000	83,333	83,333	83,334	83,333	83,333	83,334	500,000	1,000,000	24
25	Real Time Revenue Neutrality Uplift Amount	750,000	750,000	750,000	750,000	750,000	750,000	4,500,000	600,000	600,000	600,000	600,000	600,000	600,000	3,600,000	8,100,000	25
26	Real Time MVP Distribution Amount	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(75,000)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(500,000)	(575,000)	26
27	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	833,333	833,333	833,334	833,333	833,333	833,334	5,000,000	833,333	833,333	833,334	833,333	833,333	833,334	5,000,000	10,000,000	27
28	Schedule 26 A - Multi-Value Projects	3,708,333	3,708,333	3,708,334	3,708,333	3,708,333	3,708,334	22,250,000	3,708,333	3,708,333	3,708,334	3,708,333	3,708,333	3,708,334	22,250,000	44,500,000	28
29	Schedule 26 C	1,666	1,667	1,667	1,666	1,667	1,667	10,000	1,667	1,667	1,666	1,667	1,667	1,666	10,000	20,000	29
30	Schedule 26 D	833	833	834	833	833	834	5,000	833	833	834	833	833	834	5,000	10,000	30
31	Schedule 26 E	500	500	500	500	500	500	3,000	6,500	6,500	6,500	6,500	6,500	6,500	39,000	42,000	31
32	Schedule 49	50,000	50,000	50,000	50,000	50,000	50,000	300,000	91,667	91,667	91,666	91,667	91,667	91,666	550,000	850,000	32
33	PJM Madison Non-Fuel	125,000	125,000	125,000	125,000	125,000	125,000	750,000	150,000	150,000	150,000	150,000	150,000	150,000	900,000	1,650,000	33
34	Total RTO Non-Fuel Costs	6,661,330	6,661,333	6,661,337	6,661,330	6,661,333	6,661,337	39,968,000	6,513,167	6,513,167	6,513,166	6,513,167	6,513,167	6,513,166	39,079,000	79,047,000	34
35	*Transmission Revenues*	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(20,000,000)	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(20,000,000)	(40,000,000)	35
36	Total Non-Fuel Costs & Transmission Revenues	3,327,997	3,328,000	3,328,003	3,327,997	3,328,000	3,328,003	19,968,000	3,179,834	3,179,834	3,179,832	3,179,834	3,179,834	3,179,832	19,079,000	39,047,000	36
37	Less: Amount in Base Rates	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	36,458,000	37
38	Net Total Actual	289,831	289,834	289,835	289,831	289,834	289,835	1,739,000	141,668	141,668	141,664	141,668	141,668	141,664	850,000	2,589,000	38
	Under (Over) Collected																
	Non-Fuel Costs																
39	Schedule 10 FERC	(8,760)	14,303	87,708	60,070	26,262	16,125	195,708	23,662	90,221	(4,024)	5,275	(15,183)	42,015	141,966	337,674	39
40	Schedule 10	(94,497)	(68,693)	36,339	(71,588)	(48,036)	(228,135)	(474,610)	(282,689)	89,220	(128,522)	(6,846)	94,851	(41,422)	(275,408)	(750,018)	40
41	Schedule 16	(836)	(1,487)	(3,927)	(4,020)	(4,550)	(1,167)	(15,987)	(2,495)	101	(3,597)	(5,980)	(5,545)	(4,050)	(21,566)	(37,553)	41
42	Schedule 17	53,306	65,282	(54,855)	90,477	10,737	(6,563)	158,384	(4,495)	(12,599)	(43,166)	34,105	51,228	34,546	59,619	218,003	42
43	Real Time Miscellaneous	(253,760)	(85,135)	(534,419)	(24,296)	(83,333)	(97,322)	(1,078,265)	(74,541)	(2,957,952)	(75,626)	(111,303)	(82,180)	(75,743)	(3,377,345)	(4,455,610)	43
44	Real Time Revenue Neutrality Uplift Amount	(388,748)	7,202	411,212	(95,144)	443,915	(147,226)	231,211	595,587	(139,474)	14,383	(163,280)	(90,844)	118,617	334,989	566,200	44
45	Real Time MVP Distribution Amount	7,020	6,948	5,588	(6,266)	(5,498)	(6,337)	1,455	(61,993)	(71,756)	(69,830)	(41,310)	(41,808)	(41,210)	(327,907)	(326,452)	45
46	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	(146,975)	(73,092)	(8,391)	(82,917)	(178,004)	(198,996)	(688,375)	(179,917)	(34,797)	(279,705)	(256,059)	(313,013)	(164,253)	(1,227,744)	(1,916,119)	46
47	Schedule 26 A - Multi-Value Projects	(96,387)	429,908	385,247	(304,770)	(584,796)	(350,023)	(520,821)	87,487	690,757	86,832	286,174	(152,579)	117,668	1,116,339	595,518	47
48	Schedule 26 C	26,775	25,853	26,146	27,255	27,130	26,897	160,056	27,146	27,674	26,624	26,918	27,278	26,494	162,134	322,190	48
49	Schedule 26 D	(195)	(216)	(194)	(185)	(186)	(195)	(1,171)	(188)	(417)	(433)	(429)	(423)	(438)	(2,328)	(3,499)	49
50	Schedule 26 E	6,170	5,938	6,183	6,268	6,234	6,195	36,988	250	46	(188)	(125)	(55)	(229)	(301)	36,687	50
51	Schedule 49	61,054	37,755	66,148	60,808	69,172	64,624	359,561	20,224	18,657	24,739	(89,989)	21,295	38,334	33,260	392,821	51
52	PJM Madison Non-Fuel	37,911	52,262	44,958	24,355	28,612	9,751	197,849	(8,305)	(9,592)	(30,369)	(59)	(1,412)	4,895	(44,842)	153,007	52
53	Total RTO Non-Fuel Costs	(797,922)	416,828	467,743	(319,953)	(292,341)	(912,372)	(1,438,017)	139,733	(2,309,911)	(482,882)	(322,908)	(508,390)	55,224	(3,429,134)	(4,867,151)	53
54	*Transmission Revenues*	(916,627)	(1,248,205)	510,349	619,616	222,334	(247,941)	(1,060,474)	(468,523)	728,587	211,777	852,145	159,183	(1,525,749)	(42,580)	(1,103,054)	54
55	Total Non-Fuel Costs & Transmission Revenues	(1,714,549)	(831,377)	978,092	299,663	(70,007)	(1,160,313)	(2,498,491)	(328,790)	(1,581,324)	(271,105)	529,237	(349,207)	(1,470,525)	(3,471,714)	(5,970,205)	55
56	Less: Amount in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56
57	Net Total Actual	(1,714,549)	(831,377)	978,092	299,663	(70,007)	(1,160,313)	(2,498,491)	(328,790)	(1,581,324)	(271,105)	529,237	(349,207)	(1,470,525)	(3,471,714)	(5,970,205)	57
58	Revenue Conversion Factor															1.00432	58
59	Amount to be Collected (Credited) Through Rider															(5,995,996)	59

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF THE REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUES TO BE RECOVERED OR CREDITED THROUGH RIDER NO. 68 VERSUS WHAT WAS ACTUALLY COLLECTED FROM CUSTOMERS

		RTO 58							RTO 59								
Line No.	Description	July 2023	August 2023	September 2023	October 2023	November 2023	December 2023	Sub-Total	January 2024	February 2024	March 2024	April 2024	May 2024	June 2024	Sub-Total	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G) Sum (A) to (F)	(H)	(I)	(J)	(K)	(L)	(M)	(N) Sum (H) to (M)	(O) (G)+(N)	
	Rider Revenues Approved for Recovery																
1	Rate RS	135,199	135,198	135,199	135,198	135,199	135,198	811,191	(236,861)	(236,861)	(236,861)	(236,861)	(236,861)	(236,862)	(1,421,167)	(609,976)	1
2	Rate CS	17,369	17,370	17,369	17,370	17,369	17,370	104,217	(25,348)	(25,348)	(25,348)	(25,348)	(25,348)	(25,347)	(152,087)	(47,870)	2
3	Rate LLF	62,255	62,255	62,255	62,255	62,255	62,255	373,530	(124,248)	(124,248)	(124,249)	(124,248)	(124,248)	(124,249)	(745,490)	(371,960)	3
4	Rate HLF	173,339	173,339	173,339	173,339	173,339	173,339	1,040,034	(168,624)	(168,624)	(168,625)	(168,624)	(168,624)	(168,625)	(1,011,746)	28,288	4
5	Customer L	(3,552)	(3,552)	(3,553)	(3,552)	(3,552)	(3,553)	(21,314)	(7,188)	(7,188)	(7,187)	(7,188)	(7,188)	(7,187)	(43,126)	(64,440)	5
6	Customer O	1,053	1,053	1,052	1,053	1,053	1,052	6,316	(2,090)	(2,090)	(2,091)	(2,090)	(2,090)	(2,091)	(12,542)	(6,226)	6
7	Rate WP	1,164	1,165	1,165	1,165	1,165	1,164	6,988	(2,432)	(2,432)	(2,432)	(2,432)	(2,432)	(2,432)	(14,592)	(7,604)	7
8	Rate SL	55	55	55	55	55	55	330	6	6	6	6	6	6	36	366	8
9	Rate MHLS	(4)	(4)	(3)	(4)	(4)	(3)	(22)	(3)	(3)	(2)	(3)	(3)	(2)	(16)	(38)	9
10	Rate MOLS and UOLS	404	404	405	404	404	405	2,426	(573)	(573)	(573)	(573)	(573)	(573)	(3,438)	(1,012)	10
11	Rates TS, FS and MS	(25)	(25)	(25)	(25)	(25)	(25)	(150)	(148)	(148)	(148)	(148)	(148)	(149)	(889)	(1,039)	11
12	Total	387,257	387,258	387,258	387,258	387,258	387,257	2,323,546	(567,509)	(567,509)	(567,510)	(567,509)	(567,509)	(567,511)	(3,405,057)	(1,081,511)	12
	Rider Revenues Actually Collected																
13	Rate RS	132,865	148,385	134,029	97,409	95,164	132,169	740,021	(315,260)	(296,236)	(221,117)	(196,803)	(198,475)	(225,768)	(1,453,659)	(713,638)	13
14	Rate CS	16,066	17,578	16,882	13,370	12,223	14,381	90,500	(33,757)	(34,736)	(29,165)	(27,046)	(29,084)	(31,869)	(185,657)	(95,157)	14
15	Rate LLF	64,380	71,153	79,639	63,890	59,558	60,823	399,443	(111,088)	(125,417)	(115,280)	(111,965)	(125,685)	(135,578)	(725,013)	(325,570)	15
16	Rate HLF	170,970	155,070	184,268	170,298	106,538	195,115	982,259	(71,002)	(154,675)	(142,671)	(159,631)	(149,138)	(172,226)	(849,343)	132,916	16
17	Customer L	(5,917)	(6,437)	(6,442)	(5,822)	(5,159)	(4,985)	(34,762)	(4,631)	(6,286)	(5,811)	(7,102)	(7,245)	(7,523)	(38,598)	(73,360)	17
18	Customer O	1,029	1,055	1,052	1,008	1,046	1,024	6,214	1,066	(2,147)	(2,010)	(2,137)	(2,079)	(2,150)	(9,457)	(3,243)	18
19	Rate WP	1,232	1,201	1,270	1,104	1,029	1,167	7,003	(2,077)	(2,689)	(2,237)	(2,216)	(2,461)	(2,572)	(14,252)	(7,249)	19
20	Rate SL	65	52	35	51	58	57	318	10	5	(3)	109	(105)	8	24	342	20
21	Rate MHLS	(2)	(2)	(3)	(3)	(3)	(4)	(17)	(6)	(3)	(3)	(3)	(2)	(2)	(19)	(36)	21
22	Rate MOLS and UOLS	333	332	326	330	333	341	1,995	(487)	(558)	(556)	(541)	(518)	(588)	(3,248)	(1,253)	22
23	Rates TS, FS and MS	(27)	(30)	(24)	(28)	(32)	(29)	(170)	(138)	(147)	(142)	(138)	(140)	(137)	(842)	(1,012)	23
24	Total	380,994	388,357	411,032	341,607	270,755	400,059	2,192,804	(537,370)	(622,889)	(518,995)	(507,473)	(514,932)	(578,405)	(3,280,064)	(1,087,260)	24
	Under (Over) Collected																
25	Rate RS	2,334	(13,187)	1,170	37,789	40,035	3,029	71,170	78,399	59,375	(15,744)	(40,058)	(38,386)	(11,094)	32,492	103,662	25
26	Rate CS	1,303	(208)	487	4,000	5,146	2,989	13,717	8,409	9,388	3,817	1,698	3,736	6,522	33,570	47,287	26
27	Rate LLF	(2,125)	(8,898)	(17,384)	(1,635)	2,697	1,432	(25,913)	(13,160)	1,169	(8,969)	(12,283)	1,437	11,329	(20,477)	(46,390)	27
28	Rate HLF	2,369	18,269	(10,929)	3,041	66,801	(21,776)	57,775	(97,622)	(13,949)	(25,954)	(8,993)	(19,486)	3,601	(162,403)	(104,628)	28
29	Customer L	2,365	2,885	2,889	2,270	1,607	1,432	13,448	(2,557)	(902)	(1,376)	(86)	57	336	(4,528)	8,920	29
30	Customer O	24	(2)	-	45	7	28	102	(3,156)	57	(81)	47	(11)	59	(3,085)	(2,983)	30
31	Rate WP	(68)	(36)	(105)	61	136	(3)	(15)	(355)	257	(195)	(216)	29	140	(340)	(355)	31
32	Rate SL	(10)	3	20	4	(3)	(2)	12	(4)	1	9	(103)	111	(2)	12	24	32
33	Rate MHLS	(2)	(2)	-	(1)	(1)	1	(5)	3	-	1	-	(1)	-	3	(2)	33
34	Rate MOLS and UOLS	71	72	79	74	71	64	431	(86)	(15)	(17)	(32)	(55)	15	(190)	241	34
35	Rates TS, FS and MS	2	5	(1)	3	7	4	20	(10)	(1)	(6)	(10)	(8)	(12)	(47)	(27)	35
36	Total	6,263	(1,099)	(23,774)	45,651	116,503	(12,802)	130,742	(30,139)	55,380	(48,515)	(60,036)	(52,577)	10,894	(124,993)	5,749	36

DUKE ENERGY INDIANA, LLC

Comparison of the Effect of a Change in the Regional Transmission Operator ("RTO") Non-Fuel Cost and Revenue Adjustment (Rider No. 68) on the Bill of a Typical Residential Customer Using 1,000 kWh

Line No.	Description	RTO Non-Fuel Cost and Revenue Adjustment Factor Rider No. 68	Base Bill For Typical Residential Customer (1)	All Other Riders Excluding Rider No. 68 (2)	Total Bill for Typical Residential Customer Excluding Rider No. 68	RTO Non-Fuel Cost and Revenue Adjustment Amount for Rider No. 68 for 1,000 kWh's	Total Bill Including RTO Non-Fuel Cost and Revenue Adjustment Amount Rider No. 68	Increase/ (Decrease) In Total Bill From Current Factor (3)	% Increase/ (Decrease) In Total Bill From Current Factor	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
1	Proposed Factor	$ (0.000091)	$ 130.99	$ (5.97)	$ 125.02	$ (0.09)	$ 124.93	$ 0.23	0.18%	1
2	Current Approved Factor	$ (0.000322)	$ 130.99	$ (5.97)	$ 125.02	$ (0.32)	$ 124.70	NA	NA	2

(1) Reflects base rates approved in the Company's Compliance filing in Cause No. 45253, effective July 30, 2020.
(2) Reflects current rates in effect for all riders, excluding Rider No. 68, as of the date of this filing.
(3) Line 1, column G equals line 1, column F less line 2, column F.

DUKE ENERGY INDIANA, LLC

COMPANY-OWNED SCHEDULE 26 PROJECT STATUS AND ESTIMATE OF ALLOCATED SCHEDULE 26 COSTS
IURC CAUSE NO. 42736 RTO-60

				MISO	MTEP	Expected Construction Schedule			Estimated Total Project Costs			Actual	Percentage	
Line No.	Project Type	Location	Description	Approval Status	Project ID	Start	Finish	In-Service	Original	Revised	Date Revised	Costs	of Completion	Line No.
1	RECB 1 - Baseline Reliability Project	Lafayette SE to Concord	138 KV Reconductor with 954 ACSR (4.3 miles)	Approved - MTEP 07	852	2/5/08	4/24/09	4/30/09	$ 2,000,000	-	-	$ 1,257,394.14	100.00%	1
2	RECB 1 - Baseline Reliability Project	Concord to Crawfordsville	138 KV Reconductor with 954 ACSR (17.36 miles)	Approved - MTEP 07	852	5/15/08	5/15/13	6/1/13	$ 8,200,000	8,920,355	Apr-13	$ 7,174,167.73	100.00%	2
3	RECB 1 - Generator Interconnection Project	Knox County	IGCC 345 KV Switching Station [1]	Approved - MTEP 07	1263	4/14/08	4/20/10	6/1/10	$ 9,198,424	11,857,496	Jan-10	$ 11,983,364.56	100.00%	3
4	RECB 1 - Generator Interconnection Project	Knox County	IGCC 34528 Line Termination [1]	Approved - MTEP 07	1263	5/6/08	3/8/10	6/1/10	$ 168,576	192,757	Dec-09	$ 145,205.77	100.00%	4
5	RECB 1 - Baseline Reliability Project	Vigo County	Add a 3rd 345/138 kv transformer at Dresser Sub	Approved - MTEP 10	2050	12/22/09	12/31/2011	12/31/2011	$ 12,700,000	$13,443,888	Jun-11	$ 13,833,026.42	100.00%	5

Based on the MISO-approved MTEP06 through MTEP 22 the Midcontinent ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2038 is an average of approximately $9.9 million annually.

[1] In accordance with the Commission's Order dated November 20, 2007 in Cause Nos. 43114 and 43114-S1, page 59, Duke Energy Indiana will seek reimbursement of these costs under the Midcontinent ISO's RECB process.

DUKE ENERGY INDIANA, LLC

COMPANY-OWNED SCHEDULE 26-A PROJECT STATUS AND ESTIMATE OF ALLOCATED SCHEDULE 26-A COSTS
IURC CAUSE NO. 42736 RTO-60

Line No.	Project Type	MTEP Project ID	Facility ID #	Description	MISO Approval Status	Expected Construction Schedule Start	Finish	In-Service	Actual Costs	Percentage of Completion	Line No.
1	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	12/14/20	12/14/20	$ 7,786,154.71	100.00%	1
2	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	6/28/19	6/28/19	$ 5,566,614.39	100.00%	2
3	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	11/30/18	10/1/18	$ 360,234.25	100.00%	3
4	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	1/14/17	1/29/21	11/30/20	$ 152,023.38	100.00%	4
5	MVP - Multi-Value Project	2202	7286	Wabash 6986 ckt Reconductor	Approved - MTEP 11	2/17/17	7/31/18	6/1/18	$ 4,715.41	100.00%	5
6	MVP - Multi-Value Project	2202	7286	Wabash 6986 ckt Reconductor	Approved - MTEP 11	2/17/17	7/2/18	7/2/18	$ 1,744,593.87	100.00%	6
7	MVP - Multi-Value Project	2202	7287	Kokomo Delco to Greentown 138 kV Uprate	Approved - MTEP 11	11/2/17	8/7/2018	6/8/2018	$ 403,470.97	100.00%	7

Based on the MISO-approved MTEP06 through MTEP 23 the Midcontinent ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2044 is an average of approximately $42.2 million annually.

DUKE ENERGY INDIANA, LLC

COMPONENTS OF REVENUE CONVERSION FACTOR

Components of Revenue Conversion Factor:	Statutory	Effective Rate
Uncollectible Accounts Expense	0.280%	0.280%
Public Utility Fee	0.150%	0.150%
State Income Tax	4.900%	-
Federal Income Tax	21.000%	-
Subtotal Effective Rate		0.430%
Complement (1 - Effective Rate)		99.570%
Revenue Conversion Factor (1 ÷ Complement)		1.00432

STANDARD FORMAT FOR DUKE ENERGY INDIANA FILINGS
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

(1) **VERIFIED PETITION**
Petitioner's Attachment 1-A – Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors

(2) **TESTIMONY OF ART BUESCHER**
Attachment 1-A - Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors
Attachment 1-B - Determination of adjustment factors by rate groups for prior applicable period and forecasted period to be applied to current proposed calendar year
Attachment 1-C - Determination of forecasted RTO non-fuel costs and transmission revenues to be recovered or credited through Duke Energy Indiana Rider No. 68
Attachment 1-D - Comparison of projected RTO non-fuel costs and transmission revenues to actual non-fuel costs and transmission revenues incurred during the reconciliation period
Attachment 1-E - Comparison of the actual amount of revenues charged or credited and the amount approved to be charged or credited during the reconciliation period
Attachment 1-F - Comparison of the effect of a proposed change in Duke Energy Indiana Rider No. 68 adjustment factor on the bill of a typical residential customer using 1,000 Kilowatt-hours of electricity
Attachment 1-G - Schedule 26 Project Status and Estimate of Schedule 26 Costs
Attachment 1-H - Schedule 26-A Project Status and Estimate of Schedule 26-A Costs
Attachment 1-I - Components of revenue conversion factor
Attachment 1-J - Standard format for Duke Energy Indiana filings.
Attachment 1-K - Standard audit path for Duke Energy Indiana RTO filing.

(3) **WORKPAPERS OF ART BUESCHER**
Workpaper 1 – Kilowatt-hour sales by rate schedule for the twelve months ending June 2024
Workpaper 2 – KW demands for HLF rate class for the tweleve months ending June 2024
Workpaper 3 - Derivation of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months
Workpaper 4 - MISO invoice detailing MISO Schedule 10 FERC and MISO Schedule 10 costs for demand and energy
Workpaper 5 – Derivation of MISO FERC fees and MISO Schedule 10 costs
Workpaper 6 - Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor tariff

STANDARD FORMAT FOR DUKE ENERGY INDIANA FILINGS
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 7 - Summarized schedule of the MISO transmission revenue schedules
Workpaper 8 - Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues
Workpaper 9 – Derivation of Duke Energy Indiana's retail portion of PJM charges and credits associated with Madison Generating Station
Workpaper 10 - Calculation of Duke Energy Indiana's retail portion of MISO Administrative Fees, Schedules 16 and 17 cost, as well as, Real-Time Revenue Neutrality Uplift Amount, Real-Time Miscellaneous Amount and Real-Time MVP Distribution Amount
Workpaper 11 - MISO invoice detailing Schedule 26 and Schedule 26A (MVP) charges
Workpaper 12 - Duke Energy Indiana MISO Attachment GG – Calculation of Revenue Requirement for Company-owned Schedule 26 RECB projects
Workpaper 13 - Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-owned Schedule 26-A MVP projects
Workpaper 14 – Duke Energy Indiana Estimated Bill Impact By Customer Class

(4) TESTIMONY OF JOHN D. SWEZ

WORKPAPER LISTING DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 1 Kilowatt hour sales by rate schedule listed on Petitioner's Attachment 1-B

Workpaper 2 KW demands for HLF rate class listed on Petitioner's Attachment 1-B

Workpaper 3 Determination of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months as listed on Petitioner's Attachment 1-E

Workpaper 4 MISO invoice detailing Schedule 10 FERC and Schedule 10 costs for demand and energy
A) Current month Native Load Schedule 10 FERC costs for demand and energy, plus any adjustments carried to Workpaper 5
B) Current month Native Load Schedule 10 costs for demand and energy, plus any adjustments carried to Workpaper 5

Workpaper 5 Derivation of MISO Schedule 10 FERC Fees and MISO Schedule 10 costs for demand and energy
A) Monthly MISO Schedule 10 FERC fee amounts listed on Petitioner's Attachment 1-C, filed with Duke Energy Indiana's Testimony
B) Monthly MISO Schedule 10 amounts listed on Petitioner's Attachment 1-C, filed with Duke Energy Indiana's Testimony

Workpaper 6 Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor Tariff
A) Schedules of estimated and final MISO transmission revenue amounts collected under the MISO TEMT, or any successor Tariff, which are carried forward to Workpaper 9. Allocation to Operating Company

Workpaper 7 Summarized schedule of the MISO transmission revenue schedules
A) Reconciled monthly revenues added to current month's revenue to derive the amount journalized in account 456850

Workpaper 8 Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues for the reconciliation period as reported on Petitioner's Attachment 1-E, filed with Duke Energy Indiana's Testimony
A) Total Duke Energy Indiana MISO transmission revenues, less WVPA's and IMPA's revenue portion, multiplied by the retail allocation percent to create the retail portion of MISO transmission revenue. Retail allocation percentage from the IURC Order in Cause No. 45253 is 100.000%. (Amounts attributable to WVPA and IMPA need to be excluded because MISO includes such amounts in MISO's transmission revenues for the Cinergy Control Area/Zone.)

WORKPAPER LISTING DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 9 Derivation of Duke Energy Indiana's retail portion of PJM charges and credits associated with Madison Generating as approved in Cause No. 45253.

Workpaper 10 Calculation of Duke Energy Indiana's retail portion of MISO Administrative Fees for each month of the reconciliation period as billed per Schedules 16 and 17. In addition, the calculation of Duke Energy Indiana's Other MISO Standard Market Design Costs for each month as billed per MISO's Real-Time Revenue Neutrality Uplift Amount, Real-Time Miscellaneous Amount and Real-Time MVP Distribution Amount

A) Total Duke Energy Indiana MISO Administrative Fees and Other Standard Market Design Costs multiplied by the retail allocation percent to calculate the retail portion of MISO charges. Retail allocation percentage from the IURC Order in Cause No. 45253 is 100.000%.

Workpaper 11 MISO invoice detailing Schedule 26, Schedule 26A, Schedule 26C, Schedule 26D and Schedule 26-E charges

Workpaper 12 Duke Energy Indiana MISO Attachment GG – Calculation or Revenue Requirement for Company-owned Schedule 26 RECB projects

Workpaper 13 Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-owned Schedule 26-A MVP projects

Workpaper 14 Duke Energy Indiana Estimated Bill Impact By Customer Class

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: Art J Buescher III
Art J. Buescher III

Dated: August 28, 2024