FILED
September 28, 2018
INDIANA UTILITY
REGULATORY COMMISSION

TESTIMONY OF ART J. BUESCHER III
LEAD RATES AND REGULATORY STRATEGY ANALYST
DUKE ENERGY BUSINESS SERVICES LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 42736 RTO-55 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

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PETITIONER'S
EXHIBIT NO. 1
12-7-18 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"), a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy"), 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 September 28, 2018 Petition ("Petition") seeking approval of the proposed Rider No. 68 adjustment factors for the Company's bills rendered beginning with the January 2019 – Cycle 1 retail electric billing cycle (or the date of the Commission Order if later). I will also explain the change the Company is making (starting with the current proceeding) to move from quarterly filings to an annual filing for Rider No. 68.

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

A. The applicable cost and transmission revenues for the months of March 2018 through June 2018 are included in the Petition 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 2019 through December 2019, which is the proposed billing period for the rates being developed.

II. DEVELOPMENT OF SERVICES OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. ("MISO")

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE DEVELOPMENT OF THE SERVICES OFFERED BY MISO AS IT IS RELEVANT TO THIS PROCEEDING.

A. MISO began providing transmission services under its own FERC-approved Open Access Transmission Service ("MISO OATT") on February 1, 2002. At that time, the functions performed by MISO primarily focused on transmission planning, security, reliability and operations, which functions are often referred to as "Day 1 Operations." The Company has been, and continues to be, authorized by Commission to be a participating transmission owner member of MISO for Day 1 Operations.

On April 1, 2005, MISO began its day ahead and real time energy markets ("Energy Markets") in accordance with its Open Access Transmission and Energy Markets Tariff filed with the Federal Energy Regulatory Commission (now known as its Open Access Transmission and Energy and Operating Reserve

Markets Tariff and hereinafter "MISO Tariff"). The Company has been, and continues to be, authorized by the Commission to participate in MISO's Energy Markets.

On January 6, 2009, MISO commenced its Ancillary Services Market ("ASM"), which is also provided for under the MISO Tariff. In accordance with the Indiana Utility Regulatory Commission's ("Commission") Phase I Order in Cause No. 43426, dated August 13, 2008, the Commission authorized the Company to participate in ASM.

III. DEVELOPMENT OF RIDER NO. 68

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S MAY 18, 2004 ORDER IN CAUSE NO. 42359 ("MAY 18, 2004 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In Cause No. 42359, the Company proposed, among other things, Rider No. 68 to track for recovery from (or credit to) the Company's retail electric customers certain Company charges, credits and transmission revenues related to MISO. In its May 18, 2004 Order, the Commission approved the Company's proposed Rider No. 68. (May 18, 2004 Order, pp. 118-120 and 145.)

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S JUNE 1, 2005 ORDER IN CAUSE NO. 42685 ("JUNE 1, 2005 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the June 1, 2005 Order, the Commission: (i) approved certain changes in the operations of the Company (and the other investor-owned Indiana electric public utilities, which are participating members of MISO) as a result of the implementation of the Energy Markets; and (ii) determined the manner and timing of recovery of costs incurred by the Company (and the other investor-owned Indiana electric public utilities) as a result of the implementation of the Energy Markets. With respect to the Company, the June 1, 2005 Order determined (at page 37) that the following Energy Markets charges (and credits) should be included in the Company's subsequent Fuel Cost Adjustment Standard Contract Rider No. 60 proceedings:

(a) Financial Transmission Rights (hereinafter referred to as "FTR") costs;

(b) FTR congestion credits;

(c) FTR auction settlements;

(d) Virtual Bids and Offers in the Day-Ahead Market which are used for hedging jurisdictional load;

(e) Day-Ahead Recovery of Unit Commitment Costs;

(f) Excess Congestion Charge Fund Credit;

(g) Real-Time Marginal Losses Surplus Credit;

(h) RAC (*i.e.*, Reliability Assessment Commitment) Recovery of Unit Commitment Costs;

(i) Marginal Losses Surplus Credit;

(j) Inadvertent Energy Charge or Credit;

(k) Uninstructed Deviation Penalties[1,2]; and

(l) Revenue from Uninstructed Deviation Penalties[2]

The June 1, 2005 Order determined (at page 38) that Rider No. 68 shall continue to provide for the Company's non-fuel related MISO cost recovery under Energy Markets operations. The June 1, 2005 Order noted (at page 38), the Company's obligation to demonstrate the amount and reasonableness of any costs recovered under Rider No. 68, other than administrative charges imposed by MISO under Schedules 10, 10-FERC, 16 or 17 of its Tariff. The June 1, 2005 Order did not direct the Company to revise Rider No. 68.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S DECEMBER 19, 2007 ORDER IN CAUSE NO. 42736 RTO-12 ("DECEMBER 19, 2007 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the December 19, 2007 Order, the Commission approved the Company's request that 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, which involves transmission projects of other transmission owners, constitute, within the meaning of Rider No. 68, costs billed to Duke Energy Indiana by MISO under the

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1 The Commission originally limited recovery of uninstructed deviation charges to a period of one year, but in Cause No. 38707 FAC-70 authorized the Company to include these charges after the one-year period in future fuel cost recovery proceedings.

2 Upon the start of the ASM, these charges (and credits) effectively ended and were replaced by the new Excessive Energy Amount.

MISO Tariff for standard market design and that the portion of such costs allocable to Duke Energy Indiana's retail electric customers is properly includable for recovery under Rider No. 68.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S JUNE 25, 2008 ORDER IN CAUSE NO. 42736 RTO-14 ("JUNE 25 2008 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the June 25, 2008 Order, the Commission approved the Company's proposal for recovery of RECB Schedule 26 charges on Company-owned, MISO approved RECB transmission projects. The Commission authorized the Company to retain revenues related to future Company-owned RECB projects under Schedule 26. The June 25, 2008 Order required that in future proceedings the Company provide evidence that it has excluded applicable revenues and expenses from the FAC earnings test related to Company-owned RECB projects. The June 25, 2008 Order also requires the Company to describe Company-owned RECB projects and to provide estimates of Schedule 26 costs based on MISO rates and approved RECB project lists. Petitioner's Exhibit 1-G provides information on these Company-owned, MISO approved RECB projects, including estimates of Schedule 26 costs.

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 of the end of 2016: (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 was 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 April of 2018, the Company submitted to MISO its annual revenue requirement for these projects, which totaled $3,368,758, and the Company, as a transmission owner, began receiving updated revenues June 1, 2018. These projects are listed on Petitioner's Exhibit 1-G. The Company, as a transmission customer, also pays MISO its share of the corresponding Schedule 26 costs.

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

A. Yes, the Company has retained this revenue, pursuant to the June 25, 2008 Order, 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. Pursuant to the June 25, 2008 Order, the Company has excluded the applicable revenues and expenses related to its own RECB Projects from the FAC Earnings Test. See the Testimony of Company witness Suzanne E. Sieferman in

Cause No. 38707 FAC-117, which discusses the adjustments included in the Exhibit of the Earnings Test. There has been no change in methodology since its inception and the Company and the Indiana Office of Utility Consumer Counselor ("OUCC") have met to discuss RECB projects periodically.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S SEPTEMBER 24, 2008 ORDER IN CAUSE NO. 42736 RTO-15 ("SEPTEMBER 24, 2008 ORDER") AND THE COMMISSION'S JUNE 30, 2009 ORDER IN CAUSE NO. 43426 AS RELEVANT TO THIS PROCEEDING.

A. In the September 24, 2008 Order, the Commission approved the Company's request for recovery of Rider No. 68 modified charge types, upon the start of the ASM, subject to a final determination by the Commission in the ASM proceeding, Cause No. 43426, in which the Company was a Joint Petitioner. On June 30, 2009, the Commission issued its Final Order in Cause No. 43426 ("ASM Final Order"), authorizing the recovery through retail electric rates of the jurisdictional costs incurred by the Company in connection with its participation in the MISO ASM. The ASM Final Order authorizes rate treatment for various ASM credits and charges (or modified charge types) pursuant to either the Company's Fuel Adjustment proceedings or Rider No. 68 proceedings. This authorization is in addition to recovery of MISO costs previously authorized by the Commission.

Q. AS A RESULT OF THE ASM FINAL ORDER, WERE THERE ANY CHANGES TO THE MODIFIED CHARGE TYPES BEING RECOVERED UNDER RIDER NO. 68 RELATIVE TO THE SEPTEMBER 24, 2008 ORDER?

A. Yes. In an effort to synchronize Duke Energy Indiana's treatment of Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts with that of the Joint Utilities in Cause No. 43426, the ASM Final Order required the Company to include these charge types in its Fuel Cost Recovery proceedings rather than under Rider No. 68. The main difference is that Rider No. 68 allocates costs to rate class on a demand basis, while the Fuel Cost proceeding allocates costs on an energy basis. Consistent with the ASM Final Order, amounts for the aforementioned charge types are not included in this proceeding.

Also as a result of the ASM Final Order, the Company tracks the credits associated with the Contingency Reserve Deployment Failure Uplift Amount (for which such credits are included in the Real Time Revenue Neutrality Uplift Amount) in Fuel Cost Recovery proceedings.

Q. WHAT ASM CHARGES IS THE COMPANY SEEKING TO RECOVER IN THIS PROCEEDING?

A. In this proceeding, the Company has incurred modified charge types for historical periods and is seeking recovery in accordance with the September 24, 2008 Order and the ASM Final Order. The modified charge types are: (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.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S JUNE 27, 2012 ORDER IN CAUSE NO. 42736 RTO-30 ("JUNE 27, 2012 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the June 27, 2012 Order, the Commission approved the Company's request that costs assessed the Company by MISO under Schedule 26-A ("Multi-Value Project Usage Rate"), which involves transmission projects of other transmission owners constitute, within the meaning of Rider 68, costs billed to Duke Energy Indiana by MISO under the MISO Tariff for standard market design and that the portion of such costs allocable to Duke Energy Indiana's retail electric customers is properly includable for recovery under Rider No. 68. Schedule 26-A is included in this proceeding.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S SEPTEMBER 24, 2014 ORDER IN CAUSE NO. 42736 RTO-39 ("SEPTEMBER 24, 2014 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the September 24, 2014 Order, the Commission approved the Company's request to include the MISO Real-Time MVP Distribution charge type, which is a credit given to those who contributed to the cost of Multi-Value transmission projects in Rider No. 68. This charge type is included in this proceeding.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S SEPTEMBER 30, 2015 ORDER IN CAUSE NO. 42736 RTO-43 ("SEPTEMBER 30, 2015" ORDER) AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the September 30, 2015 Order, the Commission approved the Company's request to account for the cumulative change from Rate High Load Factor ("HLF") to Rate Low Load Factor ("LLF") migrations. The Company completed its annual review of changes in the number of customers and sales to HLF and LLF, resulting in an updated level of migrations as reflected in this proceeding.

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S JUNE 27, 2018 ORDER IN CAUSE NO. 42736 RTO-54 ("JUNE 27, 2018 ORDER") AS IT IS RELEVANT TO THIS PROCEEDING.

A. In the June 27, 2018 Order, the Commission approved the Company's request to move to an annual filing for Rider No. 68 and to use forecasted MISO costs and transmission revenues with a reconciliation true-up to applicable actual periods at the time of filing. Beginning with this proceeding, the Company is updating the factor calculation to include forecasted/projected MISO costs and transmission revenues for January 2019 through December 2019, which is the proposed billing period for the rates being developed.

Q. WHAT IMPACT WILL MOVING TO AN ANNUAL FILING HAVE ON THE PROJECTED RTO FACTORS IN THIS PROCEEDING?

A. As the Company transitions to an annual filing, the projected factors for this filing (and the next) are expected to be somewhat higher than normal. This is because the factors not only reflect projected costs for the January 2019 – December 2019 billing period, but also include collection of historical costs incurred (in excess of what is reflected in base rates) for the months of March 2018 to June 2018. As a result, these proposed factors for the twelve-month billing period actually include 16 months of RTO costs. This catch-up is necessary as we transition from a historical, seven (7) month lag in our rates to a "real time" recovery where rates will be in effect for the projected periods we are recovering. The historical data for the remaining "catch-up" months will be included in the next RTO filing (RTO-56).

IV. OVERVIEW OF RIDER NO. 68

Q. PLEASE BRIEFLY DESCRIBE THE COSTS 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: (i) MISO management costs billed to the Company (or a designee of the Company) by MISO under Schedules 10 (ISO Cost Recovery Adder) and 10-FERC (FERC Annual Charges Recovery), or a successor provision of either, of the MISO Tariff, or any successor Tariff of MISO, which is allocable to the Company's retail electric customers; (ii) MISO management costs billed to the Company (or a designee of the Company) by MISO under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder), or a successor provision, of the MISO Tariff, or any successor Tariff of MISO, which is allocable to the Company's retail electric customers; (iii) MISO management costs billed to the Company (or a designee of the Company) by MISO under Schedule 17 (Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder), or a successor provision, of the MISO Tariff, or any successor Tariff of MISO, which is allocable to the Company's retail electric customers; (iv) costs billed to the Company (or a designee of the Company) by MISO under the MISO Tariff, or any successor Tariff of MISO, for standard market design which is allocable to the Company's retail electric customers (including charges under Schedule 26, as authorized by the December 19, 2007 and June 25, 2008 Orders, Schedule 26-A, as authorized by the June 27, 2012 Order, and Real-Time MVP Distribution, as authorized by the September 24, 2014 Order); (v) other government mandated transmission costs the Company is required to pay on behalf of its retail electric customers; and (vi) certain MISO transmission revenues assigned to the Company (or a designee of the Company), collected by MISO under the MISO Tariff, or any successor Tariff of MISO, which are allocable to the Company's retail electric customers.

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 ADDITIONAL STEP IN THE RIDER NO. 68 PROCESS CONCERNING MISO SCHEDULE 10-FERC.

A. The Company will, for its annual Rider No. 68 filings, subtract (a) the actual amount of FERC annual charges paid by the Company (or a designee of the Company) directly to FERC (*i.e.*, outside of the MISO Schedule 10-FERC process) during the particular year from (b) the $717,000 amount of the Company's FERC annual charges built into the Company's base retail electric rates in Cause No. 42359). If the result of this subtraction is positive, then that difference will be credited to the Company's retail electric customers against the MISO Schedule 10-FERC charges under Rider No. 68.

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 any variance between the incremental amount *actually* charged (or credited), during the months in which the adjustment is in effect, and the incremental amount *to be* charged (or credited) during the months in which the adjustment is in effect. With the transition to an annual filing for Rider No. 68, this reconciliation will include the months of March 2018 through June 2018 in the current proceeding. Beginning with the RTO-56 filing (to be made in September 2019), the Company will be reconciling twelve (12) months (July – June) in each filing.

Q. PLEASE BRIEFLY DESCRIBE ANY SPECIAL PROVISIONS FOR COMMISSION APPROVAL OF COSTS COVERED BY RIDER NO. 68, WHICH ARE NOT BILLED BY MISO PURSUANT TO MISO SCHEDULES 10, 10-FERC, 16 OR 17.

A. To the extent that any costs to be recovered pursuant to Rider No. 68 are not billed by MISO to the Company (or a designee of the Company) pursuant to Schedules 10, 10-FERC, 16 or 17 of the MISO Tariff, or any successor Tariff of MISO, the Company will demonstrate in its applicable annual filing the amount and reasonableness of such costs. This requirement was also specified in the June 1, 2005 Order (June 1, 2005 Order, p. 38).

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 by the "a", "b", "c", "d" or "e" factors in the formula set forth in Rider No. 68 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 96.291% to determine the appropriate total retail electric jurisdictional portion of such costs or transmission revenues.

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 1.02096.

Q. ARE THE MODIFICATIONS TO THE FORM OF RIDER NO. 68 APPROVED BY THE COMMISSION IN ITS PREVIOUS ORDERS REFLECTED IN THE PETITION AND RIDER NO. 68 PROPOSED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, they are. The modifications to Rider No. 68 approved by the Commission in its December 15, 2004 Order in Cause No. 42736 ("December 15, 2004 Order"), its September 14, 2005 Order in Cause No. 42736 RTO-3 ("September 14, 2005 Order")[3] and its December 21, 2005 Order in Cause No. 42736 RTO-4 ("December 21, 2005 Order") are all reflected in the Petition and Rider No. 68 proposed by the Company in this proceeding.

[3] The Commission originally limited recovery of uninstructed deviation charges to a period of one year, but in Cause No. 38707 FAC-70 authorized the Company to include these charges after the one-year period in future fuel cost recovery proceedings. Upon the start of the ASM, the uninstructed deviation charge effectively ended.

V. PROPOSED RIDER NO. 68 ADJUSTMENT FACTORS FOR THE COMPANY'S JANUARY THROUGH DECEMBER 2019 RETAIL ELECTRIC BILLING CYCLES

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-A.

A. Petitioner's Exhibit 1-A is the Company's revised Standard Contract Rider No. 68. Page 3 of this Exhibit shows the Percent Share of Retail Peak developed for cost of service purposes in Cause No. 42359, as adjusted for migrations to allocate costs to each retail group.

Q. WHAT KILOWATT-HOUR CONSUMPTION AMOUNT WAS UTILIZED IN THE DEVELOPMENT OF THE PROPOSED RIDER NO. 68 ADJUSTMENT FACTORS?

A. Petitioner's Exhibit 1-B shows the individual retail rate group's billing cycle kilowatt-hour ("kWh") amount used to develop the respective proposed Rider No. 68 adjustment factors. The kWh amounts are based on the Company's actual sales to each retail rate group for the twelve (12) months ended June 2018.

Q. HAS THE COMPANY INCLUDED COSTS ASSOCIATED WITH THE ENERGY MARKETS AND ASM IN THIS FILING?

A. Yes, it has. Included in this filing are Energy Markets costs under MISO Schedule 16 and Energy Markets and ASM costs associated with Schedule 17. MISO Schedule 16 covers costs for the Financial Transmission Rights Administrative Service Cost Recovery Adder and MISO Schedule 17 (also referred to as the Day Ahead Market Administration Amount and Real Time

Market Administration Amount) covers costs for the Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder.

Q. ARE THERE ADDITIONAL CHARGES AND REVENUES THAT THE COMPANY IS INCLUDING IN THIS FILING?

A. Yes, there are. Consistent with the filings in Cause No. 42736 RTO-3, Cause No. 42736 RTO-5, Cause No. 42736 RTO-12, Cause No. 42736 RTO-15, Cause No. 42736 RTO-30, Cause No. 42736 RTO-39 and as a result of the ASM Final Order, the Company is also including in this filing the following non-fuel related costs:

a) Real-Time Revenue Neutrality Uplift Amount, exclusive of credits associated with the Contingency Reserve Deployment Failure Uplift Amount;

b) Real-Time Miscellaneous Amount;

c) Real-Time MVP Distribution Amount;

d) Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan; and

e) Schedule 26-A - Multi-Value Project Usage Rate Charges for projects of other transmission owners.

The Commission has determined that the portion of these charges and credits allocable to the Company's retail electric customers are eligible for recovery under the Company's Rider No. 68 (September 14, 2005 Order, p. 12; March 15, 2006 Order, p. 5; December 19, 2007 Order, p. 7; September 24, 2008 Order, p. 6; June 27, 2012 Order, p. 9; September 24, 2014 Order, p. 6; ASM Final Order, p. 43).

The prefiled Testimony of Mr. John D. Swez, Petitioner's Exhibit 2, supports the reasonableness of such Energy Markets and ASM non-fuel related costs.

Q. WAS THERE ANY SINGLE ADJUSTMENT IN EXCESS OF $3 MILLION INCLUDED IN THIS PROCEEDING?[4]

A. No.

Q. PLEASE DESCRIBE THE PURPOSE OF PETITIONER'S EXHIBIT 1-C.

A. Petitioner's Exhibit 1-C shows the actual booked costs and transmission revenues covered by Rider No. 68 for the months of March 2018 through June 2018. The Exhibit also includes the forecasted amounts for each item for the proposed annual billing period of January 2019 through December 2019. The Exhibit is organized to show the amounts separately for each MISO cost and/or transmission revenue item listed below:

a) MISO Schedule 10-FERC (Note: The Company's base retail electric rates include an annual amount of $717,000 for these FERC charges ($59,750 on a monthly basis). The amount in base rates is credited against the actual booked MISO Schedule 10-FERC costs in determining the amount recoverable in the current filing.).

b) MISO Schedule 10 (Combined with Schedule 10-FERC into "a" factor in Tariff calculation).

[4] 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 Exhibit A, p. 23). Since 2015, the PACE process is administered by the Sumatra model.

c) MISO Schedule 16 ("b" factor in Tariff calculation).

d) MISO Schedule 17 ("c" factor in Tariff calculation).

e) Other MISO Standard Market Design Costs and/or Other Government Mandated Transmission Costs comprised of the following ("d" factor in Tariff calculation):

a. Real Time ("RT") Miscellaneous

b. RT Revenue Neutrality Uplift

c. RT MVP Distribution

d. Network Upgrade Charge from Transmission Expansion Plan (Schedule 26)

e. Multi-Value Projects Charge (Schedule 26-A)

f) MISO Transmission Revenues Collected under the MISO OATT and assigned to Duke Energy Indiana ("e" factor in Tariff calculation).

MISO's Real-Time Revenue Neutrality Uplift Amount includes various components, as further described in the prefiled Testimony of Mr. John D. Swez in this proceeding.

Q. PLEASE CONTINUE WITH YOUR DESCRIPTION OF THE PURPOSE OF PETITIONER'S EXHIBIT 1-C.

A. Petitioner's Exhibit 1-C compares the actual net amount of the "a", "b", "c", "d" and "e" factors of the Rider No. 68 formula for both the reconciliation months and the annual forecasted period to the levels built into the Company's base retail electric rates.. The difference in these amounts (*i.e.*, a charge amount of $95,959,202) is then increased by the applicable revenue conversion factor (*i.e.*, 1.02096) as shown on page 2 of Petitioner's Exhibit 1-C and allocated to the respective retail rate groups by the percentage allocators shown on page 3 of Petitioner's Exhibit 1-A. The result is a retail charge amount of $97,970,507 to be collected from the Company's retail electric customers through the Rider No. 68 adjustment factors over an annual period for the Company's bills rendered beginning with the January 2019 – Cycle 1 billing cycle or the date of the Commission's Order if later. This result is prior to the reconciliation of MISO Management Costs and Revenues reflected on Page 1 of 3 of Petitioner's Exhibit 1-E, which reflects an over-collection of $1,038,342. Accordingly, the total amount that the Company proposes to be recovered from the Company's retail electric customers through Rider No. 68, taking into account the reconciliation amount, is $96,932,165.

Q. PLEASE EXPLAIN THE INFORMATION THAT IS INCLUDED ON PETITIONER'S EXHIBIT 1-D.

A. Petitioner's Exhibit 1-D shows the calculation of the proposed Rider No. 68 adjustment factors by retail rate group, utilizing the data from Petitioner's Exhibits 1-A, 1-B and 1-C described above. Column (A) of Petitioner's Exhibit 1-D shows the retail allocation percentages from page 3 of Petitioner's Exhibit 1-A. The charge amount calculated on Petitioner's Exhibit 1-C is shown in Column (B) of Petitioner's Exhibit 1-D, as allocated to the respective retail rate groups utilizing the percentages shown in Column (A) of Exhibit 1-D. Column

(C) of Petitioner's Exhibit 1-D is the result of the reconciliation step described above and developed on Petitioner's Exhibit 1-E. Column (D) represents the sum of Columns (B) and (C) of Petitioner's Exhibit 1-D. Column (E) of Petitioner's Exhibit 1-D shows the total kWh sales amounts for the twelve (12) months ended June 2018 developed on Petitioner's Exhibit 1-B. The adjustment factors by retail rate group are shown in Column (F) of Petitioner's Exhibit 1-D and are the result of dividing Column (D) of Petitioner's Exhibit 1-D by Column (E) of that exhibit. These factors by respective retail rate groups are then used on Page 4 of 4 of Petitioner's Exhibit 1-A.

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED ON PETITIONER'S EXHIBIT 1-E.

A. Petitioner's Exhibit 1-E develops the variance between the incremental amount actually charged or credited, whichever is applicable, for the months March 2018 through June 2018, and the incremental amount approved to be charged (or credited), for the same period of March through June 2018. Column (A) on page 1 of Petitioner's Exhibit 1-E shows the actual amounts collected (or credited), for the March through June 2018 period. The detail by month is shown on Page 3 of Petitioner's Exhibit 1-E. The revenues approved to be charged (or credited), for these same months are shown on page 2 of Petitioner's Exhibit 1-E and the total is shown in Column (B) on page 1 of Petitioner's Exhibit 1-E. The result of subtracting Column (A) from Column (B) of Petitioner's Exhibit 1-E shown in Column (C) is an over-collection of $1,038,342.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-F.

A. Petitioner's Exhibit 1-F 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 of \$1.86[5] on his or her electric bill when compared to the bills reflecting the current Rider No. 68 rate. This is a 1.6%[6] increase to each residential customer's electric bill.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-G.

A. Petitioner's Exhibit 1-G 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 PETITIONER'S EXHIBITS 1-H AND 1-I.

A. The standard format for Duke Energy Indiana filings (labeled as Petitioner's Exhibit 1-H in this proceeding) and the Standard Audit Path (labeled as Petitioner's Exhibit 1-I in this proceeding) were updated to reflect my Testimony and Workpapers.

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[5] The change is defined as the proposed change in factor from this proceeding compared to what the customer is paying today for this rider.

[6] The change is defined as the proposed factor from this proceeding compared to what the customer is paying today for this rider as a percentage of the total monthly bill of a 1000 kWh customer as of the time of this filing of \$117.74, excluding sales tax.

VI. ALLOCATION OF MISO COSTS AND CREDITS

Q. ARE THE ALLOCATION METHODS USED TO DISTRIBUTE MISO COSTS AND CREDITS BETWEEN THE COMPANY AND DUKE ENERGY OHIO, INC. THE SAME AS THOSE UTILIZED IN CAUSE NO. 42736 RTO-3 AND IN CAUSE NO. 42736 RTO-5?

A. As a result of Duke Energy Ohio joining PJM on January 1, 2012, the allocation of MISO costs and credits between the Company and Duke Energy Ohio is no longer required as MISO costs and credits are directly assigned to the Company.

VII. 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 Standard Contract Rider No. 68, Fifty-Sixth Revised Sheet No. 68, Page 1 through Page 4, as reflected in Petitioner's Exhibit 1-A, Pages 1 through 4. The Company requests that the Commission find that the Rider No. 68 adjustment factors for the Company's bills rendered beginning with the January 2019 – 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 4 of Petitioner's Exhibit 1-A.

Q. WERE PETITIONER'S EXHIBITS 1-A THROUGH 1-I 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.

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   Dated: 9-28-18

Art J. Buescher III

STANDARD CONTRACT RIDER NO. 68
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR ("MISO")
MANAGEMENT COST AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

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 MISO Management Cost and Revenues received from the MISO. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

The MISO Management Cost and Revenue Adjustment by Rate Group shall be determined by multiplying the MISO Management Cost 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. MISO Management Cost and Revenue Adjustment Factor Per Rate Group =

$$\frac{[((a + b + c + d - e) - (\$5{,}556{,}000 - \$10{,}904{,}000))\ h]\ f}{g}$$

where:

1. "a" is the MISO Management Costs forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, under Service Schedule 10 – ISO Cost Recovery Adder of the Open Access Transmission and Energy Markets Tariff for the MISO ("MISO TEMT") or any successor Tariff.

2. "b" is the MISO Management Costs forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, under Service Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder of the MISO TEMT or any successor Tariff.

3. "c" is the MISO Management Costs forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, under Service Schedule 17 – Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder of the MISO TEMT or any successor tariff.

4. "d" is the MISO Standard Market Design Costs forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, or other Government mandated transmission costs Duke Energy Indiana, LLC, or a designee of Duke, is required to pay on behalf of retail customers.

5. "e" is the MISO transmission revenues assigned to the Company, forecasted to be collected by the MISO under the MISO TEMT or any successor Tariff.

6. $5,556,000 is the annual pro forma level of MISO Management Costs of which the jurisdictional electric allocated share is included by the Company in Cause No. 42359 in the determination of basic charges for service in its Electric Tariff.

**STANDARD CONTRACT RIDER NO. 68
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR ("MISO")
MANAGEMENT COST AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS**

7. $10,904,000 is the annual pro forma level of MISO transmission revenues, of which the jurisdictional electric allocated share is included by the Company in Cause No. 42359 in the determination of basic charges for services in its Electric Tariff.

8. "f" 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. 42359 expressed as a percentage of the Company's total retail peak demand, as adjusted for rate migrations between HLF and LLF rate classes and migrations of AL and OL rate classes to the UOLS rate class.

9. "g" is the individual retail rate group's reported kilowatt-hour sales for the twelve (12) month period from July through June as a proxy for the relevant billing cycle months.

10. "h" is the revenue conversion factor used to convert the applicable charges to operating revenues.

11. The MISO Management Cost Adjustment and Revenue 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.

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

STANDARD CONTRACT RIDER NO. 68
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR ("MISO")
MANAGEMENT COST AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

ALLOCATED SHARE OF RETAIL PEAK DEMAND FOR THE COMPANY'S RETAIL CUSTOMERS BY RATE GROUP, EXPRESSED AS A PERCENTAGE OF THE COMPANY'S TOTAL RETAIL PEAK DEMAND DEVELOPED FOR COST OF SERVICE PURPOSES IN CAUSE NO. 42359
BASED ON THE TWELVE-MONTH PERIOD ENDED SEPTEMBER 30, 2002, AS REVISED FOR MIGRATIONS

Line No.	Rate Groups	KW Share of Retail Peak	Percent Share of Retail Peak	Rate Migrations	Revised KW Share Of Retail Peak	Revised Percent Share Of Retail Peak	Line No.
		(A)	(B)				
1	Rate RS	1,582,005	36.727%	-	1,582,005	36.727%	1
2	Rates CS	224,244	5.206%	-	224,244	5.206%	2
3	Rate LLF (2)	628,152	14.583%	142,775	770,927	17.897%	3
4	Rate HLF	1,808,886	41.994%	(134,915)	1,673,651	38.862%	4
5	Customer L	10,481	0.243%	-	10,481	0.243%	5
6	Customer D (2)	7,860	0.182%	(7,860)	-	0.000%	6
7	Customer O	19,045	0.442%	-	19,045	0.442%	7
8	Rate OL (1)	4,855	0.113%	(4,855)	-	0.000%	8
9	Rate WP	17,235	0.400%	-	17,235	0.400%	9
10	Rate SL	2,185	0.051%	-	2,185	0.051%	10
11	Rate AL (1)	272	0.006%	(272)	-	0.000%	11
12	Rate MHLS	282	0.007%	-	282	0.007%	12
13	Rate MOLS & UOLS (1)	69	0.002%	5,127	5,196	0.121%	13
14	Rates TS, FS, and MS	1,893	0.044%	-	1,893	0.044%	14
15	**TOTAL RETAIL**	4,307,464	100.000%	-	4,307,464	100.000%	15

(1) Reflects movement of lighting customers from AL and OL to UOLS pursuant to Order in Cause No. 42359.
(2) Reflects Customer D move to LLF effective July 31, 2017.

Issued:

Effective: Bills Rendered
January 2019 – Cycle 1

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

STANDARD CONTRACT RIDER NO. 68
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR ("MISO")
MANAGEMENT COST AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

The MISO Management Cost and Revenue Adjustment Factor by Rate Group applicable to the Bills Rendered January 2019 – Cycle 1 is as follows:

Line No.	Retail Rate Group	MISO Management Cost and Revenue Adjustment Factor per KWH	Line No.
1	Rate RS	$0.003800	1
2	Rates CS	0.004710	2
3	Rate LLF	0.003448	3
4	Rate HLF	0.003529	4
5	Customer L	0.002077	5
6	Customer D	0.000000	6
7	Customer O	0.002754	7
8	Rate WP	0.002614	8
9	Rate SL	0.001272	9
10	Rate MHLS	0.001236	10
11	Rates MOLS and UOLS	0.001090	11
12	Rates TS, FS, and MS	0.004478	12

Issued:

Effective: Bills Rendered
January 2019 – Cycle 1

DUKE ENERGY INDIANA, LLC

KILOWATT-HOUR SALES BY RATE SCHEDULE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2018

Line No.	Retail Rate Group Description	Month of: July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Twelve Months Ended June 30, 2018	Line No.
		(A)	(B)	(C)										(D)	
1	Rate RS	812,810,105	783,349,688	674,704,676	598,124,892	605,577,155	809,929,938	1,197,088,025	919,722,135	742,494,406	727,612,588	582,834,317	771,785,187	9,226,033,112	1
2	Rates CS	99,374,266	96,920,474	89,040,708	81,824,609	74,632,455	86,114,782	110,524,165	94,667,684	82,731,033	83,216,364	76,301,551	95,297,735	1,070,645,826	2
3	Rate LLF _1/	441,606,764	448,959,267	440,440,217	427,818,959	391,711,337	404,782,728	443,083,718	407,070,745	388,235,315	397,805,310	391,970,755	447,212,961	5,030,698,076	3
4	Rate HLF	976,393,145	958,210,318	961,768,363	905,201,457	885,376,742	858,245,484	893,667,201	843,228,284	838,890,978	864,232,884	880,766,764	960,520,746	10,826,502,366	4
5	Customer L	9,998,465	11,375,517	11,352,613	9,113,546	8,957,103	7,977,670	8,241,524	10,306,483	9,621,548	9,905,348	8,129,508	9,467,526	114,446,851	5
6	. Customer D _1/	-	-	-	-	-	-	-	-	-	-	-	-	-	6
7	Customer O	12,960,000	13,392,000	13,392,000	12,925,853	13,392,000	12,960,000	13,392,000	13,392,000	12,096,000	13,392,000	12,960,000	13,392,000	157,645,853	7
8	Rate OL	-	-	-	-	-	-	-	-	-	-	-	-	-	8
9	Rate WP	13,045,674	12,126,031	12,792,790	11,505,103	11,227,870	12,063,708	13,782,350	12,899,418	12,258,577	13,134,158	11,790,477	12,830,697	149,456,853	9
10	Rate SL	3,312,503	3,275,542	3,291,125	3,290,159	3,278,539	3,286,730	3,286,262	3,261,842	3,261,103	3,275,156	3,273,875	3,273,514	39,366,350	10
11	Rate AL	-	-	-	-	-	-	-	-	-	-	-	-	-	11
12	Rate MHLS	374,501	386,857	431,347	453,052	532,959	570,137	614,349	540,072	465,259	447,664	402,246	385,336	5,603,779	12
13	Rates MOLS and UOLS	9,093,760	9,101,805	9,097,197	9,092,753	9,132,596	9,127,527	9,127,038	9,082,079	9,053,282	9,043,924	8,991,348	8,959,684	108,902,993	13
14	Rates TS, FS and MS	784,063	788,883	799,160	797,787	811,444	827,151	846,207	801,093	799,766	800,556	777,750	784,275	9,618,135	14
15	**TOTAL RETAIL**	2,379,753,246	2,337,886,382	2,217,110,196	2,060,148,170	2,004,630,200	2,205,885,855	2,693,652,839	2,314,971,835	2,099,907,267	2,122,865,952	1,978,198,591	2,323,909,661	26,738,920,194	15

_1/ Reflects Customer D move to LLF Effective July 31, 2017

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR MANAGEMENT COSTS AND TRANSMISSION REVENUES TO BE RECOVERED OR CREDITED THROUGH RIDER NO. 68

Line No.	Description	Formula Reference		Applicable To Retail	Line No.
		(A)		(B)	
	Schedule 10-FERC - FERC Assessment Fees for the Months of:				
1	March 2018		$	176,906	1
2	April 2018			170,417	2
3	May 2018			165,575	3
4	June 2018			200,007	4
5	Total			712,905	5
6	Less: Amounts Built in to Base Rates (717,000 / 12 * 4)		Less:	239,000	6
7	Variance Recoverable for Schedule 10-FERC - Historical Costs			473,905	7
8	January 2019 thru December 2019 Projected Schedule 10-FERC			2,230,000	8
9	Less: Amounts Built in to Base Rates		Less:	717,000	9
10	Variance Recoverable for Schedule 10-FERC - Projected Costs			1,513,000	10
11	Total Variance Recoverable for Schedule 10-FERC			1,986,905	11
	Schedule 10 - ISO Cost Recovery Adder Charges for the Months of:				
12	March 2018			477,805	12
13	April 2018			578,114	13
14	May 2018			578,890	14
15	June 2018			311,436	15
16	Total Schedule 10 - Historical Costs			1,946,245	16
17	January 2019 thru December 2019 Projected Schedule 10			5,427,000	17
18	Total Schedule 10 and 10-FERC to Recover	(a)		9,360,150	18
	Schedule 16 - Financial Transmission Rights Administrative Service Cost Recovery Adder Charges for the Months of:				
19	March 2018			5,783	19
20	April 2018			13,612	20
21	May 2018			3,405	21
22	June 2018			11,993	22
23	Total Schedule 16 - Historical			34,793	23
24	January 2019 thru December 2019 Projected Schedule 16			147,000	24
25	Total Schedule 16 to Recover	(b)		181,793	25
	Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder Charges for the Months of:				
26	March 2018			558,406	26
27	April 2018			630,259	27
28	May 2018			317,074	28
29	June 2018			412,829	29
30	Total Schedule 17 - Historical			1,918,568	30
31	January 2019 thru December 2019 Projected Schedule 17			4,764,000	31
32	Total Schedule 17 to Recover	(c)		6,682,568	32
	Other Midcontinent ISO Standard Market Design Costs and/or Other Government Mandated Transmission Costs for the Months of:				
33	March 2018			4,066,111	33
34	April 2018			3,777,537	34
35	May 2018			3,402,047	35
36	June 2018			4,743,724	36
37	Total Other Midwest ISO Costs - Historical			15,989,419	37
38	Total Other Midwest ISO Costs - Projected			60,621,000	38
39	Total Other Midwest ISO Costs to Recover	(d)		76,610,419	39
40	Total MISO Management Costs to be Collected from Customers		$	92,834,930	40

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR MANAGEMENT COSTS AND TRANSMISSION REVENUES TO BE RECOVERED OR CREDITED THROUGH RIDER NO. 68

Line No.	Description	Formula Reference		Applicable To Retail	Line No.
		(A)		(B)	
	Midcontinent ISO Transmission Revenues collected under the Midcontinent ISO OATT and assigned to Duke for the Three Months of:				
1	April 2018		$	234,447	1
2	April 2018			224,931	2
3	May 2018			202,883	3
4	June 2018			224,134	4
5	Total MISO Transmission Revenues assigned Duke - Historical			886,395	5
6	January thru December 2019 Projected Transmission Revenues assigned to Duke			3,120,000	6
7	Total MISO Transmission Revenues assigned Duke	(e)		4,006,395	7
8	Amount MISO Costs Exceed MISO Transmission Revenues	(a+b+c+d-e)		88,828,535	8
9	Amount Built into Base Rates as Authorized in Cause No. 42359 for the Four Months Ending June 30, 2018	1,852,000 -3,634,667		(1,782,667)	9
10	Amount Built into Base Rates as Authorized in Cause No. 42359 for the Twelve Months Ending December 31, 2019	5,556,000 -10,904,000		(5,348,000)	10
11	Total Amounts Built into Base Rates		Less:	(7,130,667)	11
12	Variance Under Collected			95,959,202	12
13	Revenue Conversion Factor **(1)**	(h)		1.02096	13
14	Total Revenue Requirement to be Collected From Customers		$	97,970,507	14

Line No.	**(1)** Components of Revenue Conversion Factor:	Statutory	Effective Debt		Line No.
15	Utility Receipts Tax	1.400%		1.400%	15
16	Uncollectible Accounts Expense	0.450%		0.450%	16
17	Public Utility Fee	0.120%		0.120%	17
18	Supplemental Corporate Net Income Tax	5.625%		0.083%	18
19	Federal Income Tax	21.000%		-	19
20	Total Effective Rate			2.053%	20
21	Complement			97.947%	21
22	Revenue Conversion Factor			1.02096	22

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR MANAGEMENT COSTS AND TRANSMISSION REVENUES TO BE RECOVERED OR CREDITED THROUGH RIDER NO. 68

Line No.	Description	March 2018	April 2018	May 2018	June 2018	Total	Line No.
	Other Midcontinent ISO Standard Market Design Costs and/or Other Government Mandated Transmission Costs by Month by Category:	(A)	(B)	(C)	(D)	(E)	
1	Real Time Miscellaneous Amount	$ 23,648	$ 55,319	$ 142,571	$ (24)	$ 221,514	1
2	Real Time Revenue Neutrality Uplift Amount	$ 412,572	$ 161,559	$ 125,915	$ 1,261,670	$ 1,961,716	2
3	Real Time MVP Distribution Amount	$ (25,819)	$ (12,982)	$ (12,759)	$ (13,018)	$ (64,578)	3
4	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	$ 613,936	$ 559,289	$ 541,832	$ 649,427	$ 2,364,484	4
5	Schedule 26 A - Multi-Value Projects	$ 3,041,774	$ 3,014,352	$ 2,604,488	$ 2,845,669	$ 11,506,283	5
6	Total Other Midcontinent ISO Costs - Historical	$ 4,066,111	$ 3,777,537	$ 3,402,047	$ 4,743,724	$ 15,989,419	6
	January 2019 thru December 2019 Projected Other Midcontinent ISO Costs						
7	Projected Real Time Miscellaneous Amount					$ 1,019,000	7
8	Projected Time Revenue Neutrality Uplift Amount					$ 3,974,000	8
9	Projected Real Time MVP Distribution Amount					$ (172,000)	9
10	Projected Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan					$ 8,400,000	10
11	Projected Schedule 26 A - Multi-Value Projects					$ 47,400,000	11
12	Total Other Midcontinent ISO Costs - Projected					$ 60,621,000	12
13	Total Other Midcontinent ISO Costs for Recovery					$ 76,610,419	13

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE MIDCONTINENT ISO MANAGEMENT COST AND REVENUE ADJUSTMENT FACTORS BY RATE GROUP
FOR THE FOUR MONTH PERIOD ENDING JUNE 30, 2018 AND PROJECTED AMOUNTS FOR THE TWELVE MONTHS ENDED DECEMBER 30, 2019
TO BE APPLIED TO CUSTOMER BILLS OVER A TWELVE MONTH PERIOD ENDING DECEMBER 31, 2019

Line No.	Retail Rate Group Description	Allocated Percentage Share of Retail Peak Demands for the Company's Retail Electric Customers Based on the Twelve Months Ended September 30, 2002	Jurisdictional Costs By Rate Group to be Collected through Standard Contract Rider No. 68	Midcontinent ISO Management Costs and Revenue Adjustment Reconciliation for the Four Month Period Ending June 2018	Total	Actual Kilowatt-Hour Sales For The Twelve Months Ended June 30, 2018	Midcontinent ISO Management Cost and Revenue Adjustment Factors Per Kilowatt-Hour By Rate Group Which Recovers Costs Incurred During the Four Months Ended June 30, 2018 and Projected Twelve Months Ended December 31, 2019 Over a Twelve Month Period Ending December 31, 2019	Line No.
		(A)	(B)	(C)	(D) = (B) + (C)	(E)	(F)	
1	Rate RS	36.727%	$ 35,981,628	$ (923,014)	35,058,614	9,226,033,112	$0.003800	1
2	Rates CS	5.206%	5,100,345	(57,180)	5,043,165	1,070,645,826	0.004710	2
3	Rate LLF _1/	17.897%	17,533,782	(189,993)	17,343,789	5,030,698,076	0.003448	3
4	Rate HLF	38.862%	38,073,298	132,060	38,205,358	10,826,502,366	0.003529	4
5	Customer L	0.243%	238,068	(391)	237,677	114,446,851	0.002077	5
6	Customer D _1/	0.000%	-	-	-	-	0.000000	6
7	Customer O	0.442%	433,030	1,102	434,132	157,645,853	0.002754	7
8	Rate OL	0.000%	-	-	-	-	0.000000	8
9	Rate WP	0.400%	391,882	(1,241)	390,641	149,456,853	0.002614	9
10	Rate SL	0.051%	49,965	113	50,078	39,366,350	0.001272	10
11	Rate AL	0.000%	-	-	-	-	0.000000	11
12	Rate MHLS	0.007%	6,858	68	6,926	5,603,779	0.001236	12
13	Rates MOLS and UOLS	0.121%	118,544	168	118,712	108,902,993	0.001090	13
14	Rates TS, FS and MS	0.044%	43,107	(33)	43,074	9,618,135	$0.004478	14
15	**TOTAL RETAIL**	100.000%	$ 97,970,507	$ (1,038,342)	$ 96,932,165	26,738,920,194		15

_1/ Reflects Customer D move to LLF Effective July 31, 2017

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF MIDCONTINENT ISO MANAGEMENT COSTS AND REVENUE ADJUSTMENT
WHAT WAS ACTUALLY COLLECTED FROM CUSTOMERS VS. WHAT WAS APPROVED TO BE COLLECTED FROM CUSTOMERS
FOR THE FOUR MONTH PERIOD ENDED JUNE 30, 2018

Line No.	Retail Rate Group Description	Midcontinent ISO Management Costs and Revenue Adjustment Collected from Customers During the Four Month Period Ending June 2018	Midcontinent ISO Management Costs and Revenue Adjustment Approved to be Collected from Customers During the Four Month Period Ending June 2018	Midcontinent ISO Management Costs and Revenue Adjustment Reconciliation for the Four Month Period Ending June 2018	Line No.
		(A)	(B)	(C)	
1	Rate RS	$ 9,389,509	$ 8,466,495	$ (923,014)	1
2	Rates CS	1,246,049	1,188,869	(57,180)	2
3	Rate LLF _1/	3,917,471	3,727,478	(189,993)	3
4	Rate HLF	8,649,681	8,781,741	132,060	4
5	Customer L	51,813	51,422	(391)	5
6	Customer D _1/	-	-	-	6
7	Customer O	94,413	95,515	1,102	7
8	Rate OL	-	-	-	8
9	Rate WP	88,131	86,890	(1,241)	9
10	Rate SL	11,138	11,251	113	10
11	Rate AL	-	-	-	11
12	Rate MHLS	1,215	1,283	68	12
13	Rates MOLS and UOLS	26,116	26,284	168	13
14	Rates TS, FS and MS	9,394	9,361	(33)	14
15	**TOTAL RETAIL**	$ 23,484,930	$ 22,446,588	$ (1,038,342)	15

_1/ Reflects Customer D move to LLF Effective July 31, 2017

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF MIDCONTINENT ISO MANAGEMENT COSTS AND REVENUE ADJUSTMENT
APPROVED TO BE COLLECTED FROM CUSTOMERS DURING
THE FOUR MONTH PERIOD ENDED JUNE 30, 2018

Line No.	Retail Rate Group Description	Cause No. 42736 RTO 52 Midcontinent ISO Management Costs and Revenue Adjustment Approved to be Collected from Customers During the January through March 2018 Billing Cycles	Cause No. 42736 RTO 52 1/3 of Approved Amount for Midcontinent ISO Management Costs and Revenue Adjustment Approved to be Collected from Customers During the January through March 2018 Billing Cycles	Cause No. 42736 RTO 53 Midcontinent ISO Management Costs and Revenue Adjustment Approved to be Collected from Customers During the April through June 2018 Billing Cycles	Cause No. 42736 RTO 53 3/3 of Approved Amount for Midcontinent ISO Management Costs and Revenue Adjustment Approved to be Collected from Customers During the April through June 2018 Billing Cycles	Midcontinent ISO Management Costs and Revenue Adjustment Approved to be Collected from Customers During the Four Month Period Ending June 2018	Line No.
		(A)	(B)	(C)	(D)	(B)+(D)=(E)	
1	Rate RS	$ 5,765,979	$ 1,921,993	$ 6,544,502	$ 6,544,502	$ 8,466,495	1
2	Rates CS	832,654	277,551	911,318	911,318	1,188,869	2
3	Rate LLF _1/	2,720,192	906,731	2,820,747	2,820,747	3,727,478	3
4	Rate HLF	6,369,784	2,123,261	6,658,479	6,658,479	8,781,741	4
5	Customer L	38,929	12,976	38,446	38,446	51,422	5
6	Customer D _1/	-	-	-	-	-	6
7	Customer O	70,705	23,568	71,947	71,947	95,515	7
8	Rate OL	-	-	-	-	-	8
9	Rate WP	61,584	20,528	66,362	66,362	86,890	9
10	Rate SL	8,346	2,782	8,469	8,469	11,251	10
11	Rate AL	-	-	-	-	-	11
12	Rate MHLS	980	327	957	957	1,283	12
13	Rates MOLS and UOLS	19,427	6,476	19,808	19,808	26,284	13
14	Rates TS, FS and MS	6,920	2,307	7,055	7,055	9,361	14
15	**TOTAL RETAIL**	$ 15,895,500	$ 5,298,500	$ 17,148,088	$ 17,148,088	$ 22,446,588	15

_1/ Reflects Customer D move to LLF Effective July 31, 2017

DUKE ENERGY INDIANA, LLC

AGGREGATION OF MIDCONTINENT ISO MANAGEMENT COST AND REVENUE ADJUSTMENT REVENUES COLLECTED DURING THE FOUR MONTH PERIOD ENDING JUNE 2018

Line No.	Description	March 2018	April 2018	May 2018	June 2018	4 Months Ended June 30, 2018	Line No.
		(A)	(B)	(C)	(D)	(E)	
1	Rate RS	$ 1,736,104	$ 2,674,390	$ 2,145,326	$ 2,833,689	$ 9,389,509	1
2	Rates CS	259,056	322,410	295,796	368,787	1,246,049	2
3	Rate LLF _1/	909,165	967,173	954,572	1,086,561	3,917,471	3
4	Rate HLF	2,050,722	2,108,187	2,149,715	2,341,057	8,649,681	4
5	Customer L	13,188	13,905	11,432	13,288	51,813	5
6	Customer D _1/	-	-	-	-	-	6
7	Customer O	22,104	24,362	23,595	24,352	94,413	7
8	Rate OL	-	-	-	-	-	8
9	Rate WP	20,402	23,555	21,171	23,003	88,131	9
10	Rate SL	2,745	2,798	2,799	2,796	11,138	10
11	Rates AL	-	-	-	-	-	11
12	Rates MHLS	288	336	302	289	1,215	12
13	Rate MOLS and UOLS	6,407	6,601	6,569	6,539	26,116	13
14	Rate TS, FS, and MS	2,301	2,403	2,337	2,353	9,394	14
15	Total Retail	$ 5,022,482	$ 6,146,120	$ 5,613,614	$ 6,702,714	$ 23,484,930	15

_1/ Reflects Customer D move to LLF Effective July 31, 2017

DUKE ENERGY INDIANA, LLC

Comparison of the Effect of a Change in the Midcontinent ISO Management Cost and Revenue Adjustment (Rider No. 68) on the Bill of a Typical Residential Customer Using 1,000 kWh's

Line No.	Description	Midcontinent ISO Management Cost And Revenue Adjustment Rider No. 68	Base Bill For Typical Residential Customer (1)	All Other Riders Excluding Rider No. 68 (2)	Total Bill for Typical Residential Customer Excl. Rider No. 68	Midcontinent ISO Management Cost And Revenue Adjustment Rider No. 68 Adjustment For 1,000 kWh's	Total Bill Including Midcontinent ISO Management Cost And Revenue Adjustment 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	$ 0.003800	$ 72.10	$ 43.70	$ 115.80	$ 3.80	$ 119.60	$ 1.86	1.6%	1
2	Last Approved Factor	$ 0.001943	$ 72.10	$ 43.70	$ 115.80	$ 1.94	$ 117.74	NA	NA	2

(1) Reflects rates approved in Cause No. 42359 as adjusted for the Tax Cuts and Jobs Act of 2017 in Cause No. 45032-S2.

(2) Rates in effect as of the date of this filing.

(3) Line 1, column G, equals Line 1, column F, less Line 2, column F.

PETITIONER'S EXHIBIT 1-G (AJB)
IURC CAUSE NO. 42736 RTO-55

DUKE ENERGY INDIANA, LLC

COMPANY-OWNED SCHEDULE 26 PROJECT STATUS AND ESTIMATE OF ALLOCATED SCHEDULE 26 COSTS
CAUSE NO. 42736 - RTO 55

Line No.	Project Type	Location	Description	MISO Approval Status	MTEP Project ID	Expected Construction Schedule Start	Finish	In-Service	Estimated Total Project Costs Original	Revised	Date Revised	Actual Costs	Percentage 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, MTEP07, MTEP08, MTEP09, MTEP10, MTEP11, MTEP12, MTEP 13, MTEP 14, MTEP 15, MTEP 16 and MTEP 17 the Midwest ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2033 is an average of approximately $11.3 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 Midwest ISO's RECB process. Therefore any costs recoverable under the IGCC cost tracker will be proportionately reduced.

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

(1) VERIFIED PETITION

Petitioner's Exhibit 1-A – Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors

(2) TESTIMONY OF ART BUESCHER

Exhibit 1-A - Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors
Exhibit 1-B - Kilowatt-hour sales by rate schedule for quarter in previous year
Exhibit 1-C - Determination of MISO costs and transmission revenues to be recovered or credited through Duke Energy Indiana Rider No. 68
Exhibit 1-D - Determination of adjustment factors by rate groups for prior applicable period to be applied to current proposed quarter
Exhibit 1-E - Comparison of the actual amount of revenues charged or credited and the amount to be charged or credited
Exhibit 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
Exhibit 1-G - Schedule 26 Project Status and Estimate of Schedule 26 Costs
Exhibit 1-H - Standard format for Duke Energy Indiana filings
Exhibit 1-I - Standard audit path for Duke Energy Indiana RTO filing

(3) WORKPAPERS OF ART BUESCHER

Workpaper 1 - MISO invoice detailing Schedule 10 costs for demand and energy
Workpaper 2 - Allocation of MISO FERC fees to Operating Companies and Business Units
Workpaper 3 - MISO FERC fee allocation percentages determination
Workpaper 4 - Allocation to derive Duke Energy Indiana's portion of MISO Schedule 10 costs
Workpaper 5 - Calculation of Duke Energy Indiana's wholesale MISO Schedule 10 costs
Workpaper 6 - Data query for account 561000 and 575700 showing the wholesale and retail amounts of Schedule 10 costs
Workpaper 7 - Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor tariff
Workpaper 8 - Summarized schedule of the MISO transmission revenue schedules
Workpaper 9 - Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues
Workpaper 10 - Determination of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months

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

Workpaper 11 - 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 12 - MISO invoice detailing Schedule 26 and Schedule 26A (MVP) charges
Workpaper 13 - Duke Energy Indiana MISO Attachment GG – Calculation of Revenue Requirement for Company-owned Schedule 26 RECB projects
Workpaper 14 – HLF & LLF Rate Migration Summary
Workpaper 15 – Projected January through December 2019 MISO costs and transmission revenues.

(4) TESTIMONY OF JOHN SWEZ

STANDARD AUDIT PATH DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 1 MISO invoice detailing Schedule 10 costs for demand and energy

A) Current month Native Load Schedule 10 costs for demand and energy, plus any adjustments carried to Workpaper 4

Workpaper 2 Allocation of MISO FERC fees to Operating Companies and Business Units

B) Monthly MISO FERC fee amounts listed on Petitioner's Exhibit 1-C, Page 1 of 2, filed with Duke Energy Indiana's Testimony

C) Operating Company allocation percentages developed on Workpaper 3

Workpaper 3 MISO FERC fee allocation percentages determination. Allocations based on analysis of MISO Schedule 10 costs

D) Operating Company allocation ratio carried to Workpaper 2

E) Business Unit allocation ratio carried to Workpaper 2

Workpaper 4 Allocation to derive Duke Energy Indiana's portion of MISO Schedule 10 costs

F) Native load Schedule 10 demand and energy costs and rates from Workpaper 1

G) Duke Energy Indiana portion of total charges less wholesale costs from Workpaper 5 equals amount journalized in account 561000 and 575700 as shown on Workpaper 6

Workpaper 5 Calculation of Duke Energy Indiana's wholesale MISO Schedule 10 costs

H) Determination of final monthly wholesale amounts, which are carried over to Workpaper 4. Demand and energy rates listed on this Workpaper come from Workpaper 1. (WVPA and IMPA pay their own MISO Schedule 10 costs, so each of those organizations have been excluded for purposes of calculating the amounts shown on this document.)

Workpaper 6 Data query for account 561000 and 575700 showing the wholesale and retail amounts of schedule 10 costs

I) General ledger detail for account 561000 and 575700 broken up into estimated and final amounts for retail and wholesale costs for the relevant time period

Workpaper 7 Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor Tariff

J) Schedules of estimated and final MISO transmission revenue amounts collected under the MISO TEMT, or any successor Tariff, which are carried forward to Workpaper 8. Allocation to Operating Company

Workpaper 8 Summarized schedule of the MISO transmission revenue schedules

K) Reconciled monthly revenues added to current month's revenue to derive the amount journalized in account 456850

STANDARD AUDIT PATH DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 9 Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues as reported on Petitioner's Exhibit 1-C, Page 2 of 3, filed with Duke Energy Indiana's Testimony

L) 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 (96.291%) is from the IURC Order in Cause No. 42736. (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 10 Determination of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months

Workpaper 11 Calculation of Duke Energy Indiana's retail portion of MISO Administrative Fees for each month 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

M) 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 (96.291%) is from the IURC Order in Cause No. 42736

Workpaper 12 MISO invoice detailing Schedule 26 and Schedule 26A (MVP) charges

Workpaper 13 Duke Energy Indiana MISO Attachment GG – Calculation of Revenue Requirement for Company-owned Schedule 26 RECB projects

Workpaper 14 Summarized schedule of HLF & LLF Rate Migrations

Workpaper 15 Projected January through December 2019 MISO costs and transmission revenues