CORRECTED DIRECT TESTIMONY OF SUZANNE E. SIEFERMAN
DIRECTOR RATES AND REGULATORY PLANNING
DUKE ENERGY INDIANA, LLC
CAUSE NO. 44348 SRA 6
<u>BEFORE THE INDIANA UTILITY REGULATORY COMMISSION</u>

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

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

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Director, Rates and Regulatory Planning.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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

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

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

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

A. My testimony has several purposes: (1) to explain calculations by which the Company proposes to recover costs and/or flow through credits to customers under the Company's Standard Contract Rider No. 70 – Reliability Adjustment ("Rider 70"); (2) to detail Rider 70 rate impacts resulting from the relief requested in this proceeding; (3) to provide a summary of the accounting treatment Duke Energy Indiana proposes to match expense recognition and rate recovery; and (4) to comment on satisfaction of reporting requirements.

II. RATE CALCULATION AND IMPACTS

Q. HOW DID THE ORDER IN THE COMPANY'S MOST RECENT BASE RATE CASE (CAUSE NO. 45253) IMPACT THE RIDER 70 RELIABILITY ADJUSTMENT?

A. The Commission's Order in Cause No. 45253 ("Current Base Rate Order"), issued on June 29, 2020, made several prospective changes to the Company's Rider 70 filing, including the following:

- Removed credit embedded in base rates for sharing of margins on traditional non-native sales and modified sharing percentage from 50% to 100% sharing of positive margins with customers;
- Recognized a new type of non-native sale, termed short-term bundled non-native sales, and established retail credit of $11.748 million in base rates with sharing of margins above and below this amount (down to zero) 50% with customers;
- Modified the stacking logic for long-term commitment generating units (*i.e.*, coal-fired and combined-cycle natural gas units) used in the Company's production costing model to determine native versus non-native fuel costs;
- Updated the proposed annual base amount for PowerShare® costs from $1,023,000 to $9,911,000; and
- Modified the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales.

Almost all of these changes will be effective on a prospective basis, beginning with the operational month of July 2020 (to be included in the SRA 7 filing). The current Rider 70 Reliability Adjustment filing covers the operational months of June 2018 through May 2020, which are all governed by the Company's previous general rate case order, described below. The only exception is for the modified factor calculation for Rate HLF, which became effective upon approval of the Company's new retail base rates beginning July 30, 2020.

Q. PLEASE EXPLAIN THE RIDER 70 RELIABILITY ADJUSTMENT THAT WAS APPROVED IN THE COMPANY'S PRIOR GENERAL RATE CASE.

A. The Company's prior general retail base rate case, Cause No. 42359 ("Prior Base Rate Order"), authorized the creation of Rider 70. As approved in that Cause, Rider 70 provided for the adjustment of the following economic items: (1) the recovery of summer reliability purchased power demand (or "capacity") costs; (2) the recognition of the differential between the $1,023,000 included in base rates associated with Duke Energy Indiana's PowerShare® program and actual costs incurred for this program; (3) sharing, on a 50/50 basis, the differential between net non-native sales profits realized by the Company and the $14,747,000 net profit level for non-native sales included in the determination of Duke Energy Indiana's revenue requirement in Cause No. 42359; and (4) the recognition of a standard reconciliation provision.

Q. PLEASE DESCRIBE THE CHANGES APPROVED BY THE COMMISSION IN PRIOR RIDER 70 PROCEEDINGS.

A. Since its approval in Cause No. 42359, the Company has filed annually to update its Rider 70 in Cause Nos. 42695, 42870, 43074, 43302, 43505, 43715, 43906, 44035, 44214, 44348, 44348 SRA 1, 44348 SRA 2, 44348 SRA 3, 44348 SRA 4 and 44348 SRA 5. Notably, since Cause No. 42870, Petitioner has offered the CallOption feature of its PowerShare® program to customers throughout the year, rather than only during the summer months with recovery of the Company's annual (rather than just summer) PowerShare® program costs. In Cause No.

43302, the Commission approved Petitioner's request to include recovery of reasonable and necessary reliability power purchases on a year-round basis. In addition, in Cause No. 44035, the Commission granted cost recovery authority associated with a permanent year-round PowerShare® program.

Q. WHAT IS THE TIMEFRAME COVERED BY THIS FILING?

A. While the Company was in the process of completing its most recent base rate case, it filed notice with the Commission suspending the filing of Rider 70 during the pendency of that proceeding. The testimony and rates in this proceeding, the first one following completion of the most recent base rate case, reflect results for two (2) separate twelve-month ended periods (twelve-months ended May 2019 and twelve-months ended May 2020). The data from these two (2) periods will be used for: (1) purchased and sold capacity amounts; (2) peak load management costs; and (3) net non-native sales profits, net of prior period adjustments. The prior period adjustments resulted from updating and correcting relevant cost and revenue data for non-native sales made in periods preceding June 1, 2018. For more detail, please see Petitioner's Exhibit 6-F, line 2, and the prefiled Direct Testimony of Mr. Scott A. Burnside.

Q. WERE THERE ANY NET PURCHASED CAPACITY COSTS THAT DUKE ENERGY INDIANA PROPOSES TO RECOVER VIA RIDER 70 IN THIS PROCEEDING FOR THE JUNE 2018 THROUGH MAY 2019 TWELVE-MONTH ENDED PERIOD?

A. No. With the Midcontinent Independent System Operator, Inc. ("MISO") Resource Adequacy construct beginning June 1, 2013, all load is charged the Auction Clearing Price ("ACP") and all resources are paid the ACP in MISO's annual Planning Resource Auction ("PRA"). For the June 2018 through May 2019 period, the Company elected to fully participate in the PRA, where capacity purchases of Zonal Resource Credits ("ZRCs") were made for native load and generation capacity was sold at an ACP of $10.00/MW-day for generation capacity and the Company paid $9.9602/MW-day for load. The Company was long on capacity going into the PRA for the June 2018 to December 2018 period and the January 2019 to May 2019 period.

In addition to the capacity purchases and sales in the MISO PRA, beginning January 2019 the Company also had bilateral capacity purchases through a Purchase Power Agreement ("PPA") with Staunton Solar, LLC which was approved by the Commission in November 2017 in Cause No. 44953. For the twelve-month period ended May 2019, capacity purchases under this agreement totaled $48,920. Over the entire 2018/2019 MISO Planning Year, the Company's net position was long which resulted in net capacity revenue of $475,457 to the Company; therefore, there were no net capacity purchases to include in Rider 70 during the twelve months ended May 2019. The detailed capacity purchases and sales activity for this period can be seen on Petitioner's Confidential Exhibit 6-C.

Q. WERE THERE ANY NET PURCHASED CAPACITY COSTS TO RECOVER FOR THE JUNE 2019 THROUGH MAY 2020 TWELVE-

MONTH ENDED PERIOD?

A. No. For the June 2019 through May 2020 period, the Company elected to fully participate in the PRA, where capacity purchases of ZRCs were made for native load and generation capacity was sold at an ACP of $2.99/MW-day for both load and generation capacity. In addition to the capacity purchases and sales in the MISO PRA, the Company also had bilateral capacity purchases through the Staunton Solar PPA which totaled $138,822 for this period. Going into the 2019/2020 MISO Planning Year, the Company's net position was long which resulted in net capacity revenue to the Company; therefore, there were no net capacity purchases to include in Rider 70 during the twelve months ended May 2020. The detailed capacity purchases and sales activity for this period can be seen on Petitioner's Confidential Exhibit 6-D.

Q. WERE ANY CAPACITY SALES MADE IN THE PERIOD COVERED BY THE CURRENT RIDER 70 PROCEEDING?

A. Yes. Through the Company's participation in MISO's PRA, as discussed in both my testimony and Mr. Michael Chen's direct testimony in this proceeding, the Company's long position in both reporting periods resulted in net capacity sales. There were no bilateral capacity-only sales transactions (i.e. non-MISO sales transactions) during the June 2018 through May 2020 periods covered in this filing.

Q. HOW ARE CAPACITY SALES TREATED IN RIDER 70?

A. Sales of surplus capacity are from either Duke Energy Indiana generating capacity or prior capacity purchases. During the MISO planning year, where both capacity purchases and capacity sales exist, sales proceeds first offset the cost of those purchases. To the extent capacity sales occur during a MISO planning year without capacity purchases or are in excess of capacity purchase costs over the entire MISO planning year, such amounts are included in the non-native profit-sharing mechanism.

As shown on Petitioner's Confidential Exhibit 6-C, during the period June 1, 2018 through May 31, 2019, $23,436,423 in total capacity purchases were fully offset by generating capacity sales made in the PRA. The amount of capacity sales proceeds in excess of the capacity purchase costs of $475,457 has been included in the calculation of non-native sales profits detailed on Petitioner's Exhibit 6-F.

As shown on Petitioner's Confidential Exhibit 6-D, during June 1, 2019 through May 31, 2020, the second twelve-month ended period included in this proceeding, $7,102,545 in total capacity purchases were fully offset by generating capacity sales made in the PRA. The remaining capacity sales proceeds (in excess of the capacity purchase costs) of $204,144 have been included in the calculation of non-native sales profits detailed on Petitioner's Exhibit 6-F.

Q. PLEASE DESCRIBE THE PEAK LOAD MANAGEMENT COSTS THAT DUKE ENERGY INDIANA PROPOSES TO RECOVER AS SHOWN IN PETITIONER'S CONFIDENTIAL EXHIBIT 6-E.

A. The Company seeks to recover peak load management costs associated with a customer-specific peak load management contract with Steel Dynamics, Inc. ("SDI") and offerings under PowerShare®. On October 21, 2009, in Cause No. 43737 the Commission approved, among other things, the recovery of SDI demand response incentive payments via Rider 70. On June 23, 2010, the Commission granted renewed authority to offer PowerShare® on a year-round basis and collect associated costs through May 31, 2012. As referenced earlier in my testimony, on May 30, 2012, in Cause No. 44035, the Company was granted cost recovery authority associated with a permanent year-round PowerShare® program.

Rider 70 provides for the tracking (both up and down) of actual PowerShare® CallOption premiums and CallOption and QuoteOption energy credits. The tracking feature is based on a comparison of actual costs incurred to the annual *pro forma* test period expense level approved by the Commission. In this instance, since the periods being reconciled are from June 2018 through May 2020, the annual *pro forma* test period expense level is from the Company's prior Base Rate Order (Cause No. 42359). As described in more detail in the testimony of Duke Energy Indiana witness Mr. Andrew Taylor, PowerShare® costs for the June 2018 through May 2019 period totaled **<CONFIDENTIAL>**[redacted]**<CONFIDENTIAL>**. The PowerShare® program is a retail only program, so the total PowerShare® costs are properly assignable to retail customers. Rider 70 also provides for collection of SDI demand response incentive payments that totaled

<CONFIDENTIAL>[redacted]**<CONFIDENTIAL>** for the 12-month period ended May 31, 2019. The total of these peak load management costs is $9,793,879.

PowerShare® costs for the June 2019 through May 2020 period totaled **<CONFIDENTIAL>**[redacted]**<CONFIDENTIAL>**. The SDI demand response incentive payments totaled **<CONFIDENTIAL>**[redacted]**<CONFIDENTIAL>** for the 12-month period ended May 31, 2020. The total of these peak load management costs for this period is $9,467,404.

The total for these two (2) twelve-month ended periods is $19,261,283. The amount of annual PowerShare® costs included in the Company's *pro forma* test period expenses approved by the Commission in Cause No. 42359 is $1,023,000. Because the total actual peak load management costs incurred are more than the approved test period expense levels for both reporting periods, Rider 70 includes a $17,215,283 charge for the differential. The development of this amount is observable on Petitioner's Confidential Exhibit 6-E, attached hereto.

Q. PLEASE DESCRIBE THE NON-NATIVE SALES PROFIT COMPONENT OF RIDER 70 AS SHOWN IN PETITIONER'S EXHIBIT 6-F.

A. In Cause No. 42359, the Commission found that Duke Energy Indiana's base rates should include a credit for non-native sales profits of $18,700,000. The Commission also found that Duke Energy Indiana's non-native sales profits and base rates should include a reasonable level of trading expenses and the annual trading expense amount was determined to be $3,953,000. Further, future non-native sales revenues are to be reduced by trading expenses fixed at the test period level (*i.e.*, $3,953,000 before jurisdictional allocation). Therefore, for Rider 70 purposes, the annual amount of net jurisdictional non-native sales profits included in Duke Energy Indiana's base rates is $14,747,000 through the operational month of June 2020. The Commission's Prior Base Rate Order provided for 50/50 sharing of net profits above and below the base level amount ($14,747,000), with the stipulation that, for Rider 70 computational purposes, non-native sales profits could never be below zero.

The prefiled direct testimony of Mr. Burnside includes a discussion of the methodologies used to determine the level of gross non-native sales profit realized by the Company. Mr. Burnside's testimony also supports the prior period adjustments utilized in determining the current Rider 70 filing's net non-native sales profit.

Q. WHAT WERE THE RESULTS FOR THE NON-NATIVE SALES PROFIT COMPONENT OF RIDER 70 FOR THE TWELVE-MONTH ENDED MAY 31, 2019 PERIOD AS SHOWN IN PETITIONER'S EXHIBIT 6-F?

A. The computations performed by Mr. Burnside are summarized on Petitioner's Exhibit 6-F. The calculation of non-native sales profit for the twelve months ended May 31, 2019 is $2,168,034 (see Petitioner's Exhibit 6-F, Line 1, Column A). This amount was adjusted by a net prior period adjustment of $1,926 applicable to periods preceding June 2018 (which was also calculated by Mr.

Burnside; see Petitioner's Exhibit 6-F, Line 2, Column A), and then reduced by $3,953,000 of fixed trading expenses (see Petitioner's Exhibit 6-F, line 3, Column A). The result is $(1,783,040), which is before retail jurisdictional allocation. The amount of net non-native sales profit/(loss) attributable to retail customers for the twelve-month ended May 31, 2019 period of this filing is $(1,636,670) (see Petitioner's Exhibit 6-F, Line 6, Column A). This amount is compared to the net non-native sales profits of $14,747,000, to determine the amount by which actual net non-native sales profits exceed (or are less than) the net credit included in base rates for that period. The resulting amount is then multiplied by 50% to get the amount due to or from customers for this period. The computation detailed above reflects the Commission directed sharing of non-native sales margins and results in a $7,373,500 charge to customers (see Petitioner's Exhibit 6-F, Line 10, Column A).

Q. WHAT WERE THE RESULTS FOR THE NON-NATIVE SALES PROFIT COMPONENT FOR THE TWELVE-MONTH ENDED MAY 31, 2020 PERIOD?

A. The computations for this second twelve-month ended period are also shown on Petitioner's Exhibit 6-F in Column B. The non-native sales profit for the twelve months ended May 31, 2020 is $955,623. There was no prior period adjustment amount applicable to this period, but the amount was reduced by $3,953,000 of fixed trading expenses (see Petitioner's Exhibit 6-F, line 3, Column B). The result is $(2,997,377), which is before retail jurisdictional allocation. The amount of net non-native sales profit/(loss) attributable to retail customers for the twelve-month ended May 31, 2020 period of this filing is $(2,751,323) (see Petitioner's Exhibit 6-F, Line 6, Column B). This amount is compared to the net non-native sales profits of $14,747,000, to determine the amount by which actual net non-native sales profits exceed (or are less than) the net credit included in base rates for that period. The resulting amount is then multiplied by 50% to get the amount due to or from customers for this period. The computation detailed above reflects the Commission directed sharing of non-native sales margins and results in a $7,373,500 charge to customers (see Petitioner's Exhibit 6-F, Line 10, Column B).

Q. ARE THERE OTHER ITEMS THAT AFFECT THE CALCULATION OF COSTS TO BE COLLECTED THROUGH RIDER 70?

A. Yes, there are. Rider 70 includes a standard reconciliation provision in which the Company determines the difference between Rider 70 amounts approved for recovery and Rider 70 amounts actually collected from customers. One reason this reconciliation is necessary is because the Rider 70 factor is calculated based on estimates of kilowatt-hour usage for each rate group. Actual usage will vary from the estimate, resulting in either an over-billing or under-billing of amounts. Any over-billing or under-billing of Rider 70 amounts will be reflected in subsequent requests for changes in Rider 70 amounts as a reconciliation adjustment to be recovered or credited. Accordingly, the Company has prepared reconciliations of billed Rider 70 amounts corresponding to those authorized for recovery in Cause Nos. 44348 SRA 4 and SRA 5, Commission Orders dated February 21, 2018 and

March 6, 2019, respectively. The Order in the SRA 4 proceeding authorized the Company to recover $14,968,866 of Rider 70 costs after retail jurisdictional allocation over a 12-month period. The amount actually collected for the 12-months ended February 28, 2019 was $15,441,654. The reconciliation results in a $472,788 over-collection (see Petitioner's Exhibit 6-G).

The Order in the SRA 5 proceeding authorized the Company to recover $14,697,722 of Rider 70 costs after retail jurisdictional allocation over a 12-month period. The amount actually collected for the 12-months ended February 29, 2020 was $14,552,118. The reconciliation results in a $145,604 under-collection (see Petitioner's Exhibit 6-H). The Company included the SRA 4 over-billing amount as a credit to customers and the SRA 5 under-billing amount as a charge to customers in the determination of the proposed Rider 70 billing factors in this proceeding.

Q. HAVE YOU CALCULATED THE BILLING FACTORS FOR THE VARIOUS RETAIL RATE GROUPS UNDER THE COMPANY'S PROPOSED RIDER 70 UPDATE USING THE COST COMPONENTS AND AMOUNTS YOU HAVE DESCRIBED?

A. Yes, I have. Petitioner's Exhibit 6-B includes costs by rate group for each of the cost components, using a 12 months ended coincident peak demand (12CP) allocation from Cause No. 42359, adjusted to reflect the impact of customer migrations, to allocate peak load management costs and non-native sales profits to rate groups. These amounts allocated to each rate group (except for HLF) and the reconciliation adjustment amounts by rate group from the reconciliation calculations discussed above, are divided by the corresponding kWh sales for the twelve months ended May 31, 2020, to obtain the factors that are being proposed for future Rider 70 billings herein. For developing the HLF rates, the revenue requirement amount is divided by KW demands for the twelve months ended May 31, 2020 to determine the proposed Rider 70 rate.

Q. HOW DO THE PROPOSED BILLING FACTORS COMPARE TO THE RIDER 70 FACTORS CURRENTLY BEING BILLED TO CUSTOMERS?

A. Petitioner's Exhibit 6-I compares the Rider 70 billing factors proposed in this proceeding to Rider 70 billing factors currently being billed Duke Energy Indiana's customers, as approved in the Compliance filing in the Company's most recent base rate case in Cause No. 45253. In addition, Petitioner's Exhibit 6-J shows the impact of the proposed change in the Reliability Adjustment factor on the total monthly bill of a typical residential customer using 1,000 kilowatt-hours. A typical residential bill will increase by approximately $1.36[1] or 1.1% compared to the last approved factor if the rates proposed in this filing are approved.

III. ACCOUNTING TREATMENT

Q. PLEASE EXPLAIN DUKE ENERGY INDIANA'S ACCOUNTING TREATMENT RELATING TO COSTS AND/OR CREDITS REFLECTED

[1] This change represents an increase in the Reliability Adjustment factor from this proceeding, as compared to what the customer is paying today, as a percentage of the total monthly bill of a 1000 kWh customer as of September 1, 2020, excluding utility receipts tax and sales tax.

IN RIDER 70.

A. Duke Energy Indiana defers peak load management amounts and the demand/capacity costs of jurisdictional reliability purchased power expenses. The Company also records either a regulatory asset or liability related to the true-up of the reconciliation of actual Rider 70 billings to amounts approved for recovery and the recovery of the differential in non-native sale profits reflecting the Commission-approved sharing arrangement. Such deferrals allow Duke Energy Indiana to match its recognition of Rider 70 related expenses with corresponding tracker revenues.

IV. REPORTING REQUIREMENTS

Q. DO THE EXHIBITS AND WORKPAPERS BEING SUBMITTED IN THIS PROCEEDING SATISFY THE REPORTING REQUIREMENTS DETAILED ON ATTACHMENTS 1 THROUGH 4 OF THE SETTLEMENT AGREEMENT THAT WAS ORIGINALLY APPROVED IN CAUSE NO. 42870 AND SUBSEQUENTLY UPDATED IN CAUSE NO. 43906?

A. Yes. The Company has attached Petitioner's Exhibit 6-K, which is a red-lined version of its tariff (Petitioner's Exhibit 6-A) that identifies unique adjustments to the tariff in this year's Rider 70. This satisfies the reporting requirements for Attachment 1 of the Settlement Agreement approved in Cause No. 42870. Confidential Exhibits 4-D and 4-E that accompany Mr. Andrew Taylor's testimony satisfies the reporting requirements from Attachment 2 related to peak load management/PowerShare®. The requirements detailed on Attachment 3 of the Settlement Agreement will be addressed by Mr. Burnside's submissions (subject to confidentiality protections). Petitioner's Confidential Exhibits 6-C and 6-D, along with workpapers to be provided, satisfies the requirements detailed on Attachment 4 of the Settlement Agreement in Cause No. 42870, which was updated in consultation with the OUCC in Cause No. 43906.

Q. IS THERE ANYTHING ADDITIONAL YOU WOULD LIKE TO MENTION?

A. Yes. I wanted to briefly mention a newer type of non-native contract the Company is pursuing that combines the sales of both capacity and energy and is short-term in nature (five years or less). This concept was introduced in the Company's most recent retail base rate case proceeding as a way to address a need in the wholesale market for a short-term, combined capacity and energy product at a price that is less than the Company's fixed costs and more competitive with the current MISO markets. In Cause No. 45253, the Commission approved 50/50 sharing of margins realized on these newer "short-term bundled non-native contracts" through the Rider 70 mechanism. The Company will start calculating and sharing margins on these contracts beginning with financial results for the month of July 2020, which will be included in the Company's SRA 7 proceeding. The Company currently has one such contract and will be pursuing more of these "short-term bundled non-native" contracts with wholesale customers in the future. Unlike the traditional firm wholesale native load sales contracts that the Company has entered into in the past, these newer contracts are priced below the Company's embedded cost and do not receive an allocation of Duke Energy Indiana's fixed production costs in the cost of service studies used in retail base rate proceedings.

Q. IS THERE ANYTHING INCLUDED IN THE CURRENT RIDER 70 FILING (SRA 6) FOR 50/50 SHARING OF ANY POSITIVE MARGINS ON SHORT-TERM BUNDLED NON-NATIVE SALES?

A. No, there is not. As discussed earlier in my testimony, the reporting periods of June 2018 through May 2020 included in this filing are governed by the Company's prior base rate order (Cause No. 42359). The Company presented these new short-term bundled non-native sales for consideration in its most recent base rate case (Cause No. 45253), where it received approval from the Commission of its proposed ratemaking treatment for these sales. The Company's next Rider 70 filing will include results for the month of June 2020 (under Cause No. 42359) and the months of July 2020 through May 2021 (under Cause No. 45253). Margins on short-term bundled non-native sales will be calculated for the July 2020 through May 2021 period and net positive margins for that period will be shared 50/50 in that Rider 70 proceeding.

V. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS 6-A, 6-B, AND 6-F THROUGH 6-K AND PETITIONER'S CONFIDENTIAL EXHIBITS 6-C THROUGH 6-E PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

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STANDARD CONTRACT RIDER NO. 70 - RELIABILITY ADJUSTMENT

Calculation of Adjustment

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

Reliability Adjustment Factor:

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

where:

1. "a" equals year-round purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with reliability purchases as approved by the Commission. The total cost of reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.
2. "b" is the total year-round amount of bill credit provided to customers under the Company's PowerShare® program including any additional demand response amounts determined to be includable by the Commission, less the annual level built into base rates in Cause No. 45253 ($9,911,000).
3. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. 45253.
4. "d" is the individual retail rate group's allocated percentage share of the Company's average four monthly coincident retail peak demands as developed for cost of service purposes in Cause No. 45253.
5. "e" represents actual net profits realized from non-native sales of excess generation to MISO.
6. "f" represents actual net profits realized from remaining non-native sales (excludes amount in "e" above), including short-term bundled non-native sales.
7. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

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

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

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

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STANDARD CONTRACT RIDER NO. 70 -
RELIABILITY ADJUSTMENT
APPLICABLE TO ALL 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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1000 East Main Street
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IURC No. 15
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STANDARD CONTRACT RIDER NO. 70 - RELIABIITY ADJUSTMENT APPLICABLE TO ALL RETAIL RATE GROUPS

Line No.	Retail Rate Group	Reliability Adjustment Factor Per KWH 1/ (A)	Reliability Adjustment Factor Per Non-Coincident KW (B)	Line No.
1	Rate RS	$0.001253		1
2	Rates CS and FOC	0.001617		2
3	Rate LLF	0.001061		3
4	Rate HLF		$0.686072	4
5	Customer L	0.000698		5
6	Customer O	0.000891		6
7	Rate WP	0.000824		7
8	Rate SL	0.000449		8
9	Rate MHLS	0.000393		9
10	Rates MOLS and UOLS	0.000364		10
11	Rates TS, FS and MS	0.001420		11

1/ Proposed factors above reflect calculations, peak load allocators and base amounts approved by the Commission in Cause No. 42359 as applied to data for the historical periods of June 2018 through May 2020.

Issued: Pending

Effective:

DUKE ENERGY INDIANA, LLC

DETERMINATION OF STANDARD CONTRACT RIDER NO. 70 BILLING FACTORS BY RETAIL RATE SCHEDULE REFLECTING RECOVERY
OF RELIABILITY PURCHASED POWER CAPACITY COSTS, NET PEAK LOAD MANAGEMENT COSTS AND SHARED PROFITS FROM NON-NATIVE SALES
FOR THE PERIOD JUNE 2019 THROUGH MAY 2020 TO BE APPLIED TO CUSTOMER BILLS OVER A TWELVE-MONTH PERIOD

Line No.	Description	Percentage Share of Retail System Peak Demand For Allocation Purposes in IURC Cause No. 42359 _1/ (A)	Purchase Power Capacity Costs Costs for the Twelve-Month Periods Ended May 2019 and May 2020 by Rate Schedule (B)	Peak Load Management Costs Attributable to the Twelve-Month Periods Ended May 2019 and May 2020 by Rate Schedule (C)	Non-Native Sales Profits for the Twelve-Month Periods Ended May 2019 and May 2020 by Rate Schedule (D)	(Over) Under Collection of Costs Approved in Cause No. 44348 SRA 4 (E)	(Over) Under Collection of Costs Approved in Cause No. 44348 SRA 5 (F)	Total Net Jurisdictional Costs By Rate Schedule to Be Collected Through Standard Contract Rider No. 70 (G)	Kilowatt-Hour Sales For The Twelve-Month Period Ended May 31, 2020 (H)	Reliability Adjustment Factors Per Kilowatt-Hour by Rate Schedule (I)	KW For The Twelve-Month Period Ended May 31, 2020 (J)	Reliability Adjustment Factor Per KW by Rate Schedule (K)	Line No.
	Retail Rate Group												
1	Rate RS	36.727%	$ -	$ 6,322,657	$ 5,416,131	$ (449,299)	$ 13,303	$ 11,302,792	9,019,805,914	$ 0.001253			1
2	Rates CS and FOC	5.206%	-	896,228	767,729	(19,436)	9,439	1,653,960	1,022,574,659	0.001617			2
3	Rate LLF	17.897%	-	3,081,019	2,639,270	(188,678)	(160,504)	5,371,107	5,063,734,131	0.001061			3
4	Rate HLF	38.862%	-	6,690,203	5,730,979	193,224	282,932	12,897,338	9,952,464,804		18,798,816	0.686072	4
5	Customer L	0.243%	-	41,833	35,835	(5,691)	2,133	74,110	106,165,008	0.000698			5
6	Customer O	0.442%	-	76,092	65,182	(286)	(163)	140,825	158,042,619	0.000891			6
7	Rate WP	0.400%	-	68,861	58,988	(2,481)	(1,097)	124,271	150,903,483	0.000824			7
8	Rate SL	0.051%	-	8,780	7,521	227	326	16,854	37,526,115	0.000449			8
9	Rate MHLS	0.007%	-	1,205	1,032	(16)	(15)	2,206	5,616,232	0.000393			9
10	Rates MOLS and UOLS	0.121%	-	20,830	17,844	(70)	(620)	37,984	104,313,465	0.000364			10
11	Rates TS, FS and MS	0.044%	-	7,575	6,489	(282)	(130)	13,652	9,615,155	0.001420			11
12	Total Retail	100.000%	$ -	$ 17,215,283	$ 14,747,000	$ (472,788)	$ 145,604	$ 31,635,099	25,630,761,585				12

_1/ The peak load allocators from Cause No. 42359 were used to allocate the retail totals for the Peak Load Management costs and Non-Native Sales margins to the retail rate group level as this filing includes two historical twelve-month ended reporting periods prior to approval of the new base rate order.

PETITIONER'S EXHIBIT 6-C IS CONFIDENTIAL

PETITIONER'S EXHIBIT 6-D IS CONFIDENTIAL

PETITIONER'S EXHIBIT 6-E IS CONFIDENTIAL

DUKE ENERGY INDIANA, LLC

DETERMINATION OF NET NON-NATIVE SALES PROFITS SUBJECT TO SHARING
FOR THE TWELVE-MONTH PERIODS ENDED MAY 2019 AND MAY 2020

Line No.	Description	Twelve-Month Period Ended May 31, 2019 Amount (A)	Twelve-Month Period Ended May 31, 2020 Amount (B)	Total Amount (C) (A) + (B)	Line No.
1	Actual Gross Profits from Non-Native Sales Realized During the Applicable Twelve-Month Ended Period	$ 2,168,034	$ 955,623	$ 3,123,657	1
2	Plus: Net Prior Period Adjustment Attributable to Periods Preceding June 2018 1/	1,926	0	1,926	2
3	Less: Fixed Trading Expenses Approved in Cause No. 42359	3,953,000	3,953,000	7,906,000	3
4	Net Non-Native Sales Profits (Loss)	$ (1,783,040)	$ (2,997,377)	$ (4,780,417)	4
5	Retail Allocation Percentage	91.791%	91.791%	91.791%	5
6	Net Non-Native Sales Profits (Loss) Allocated to Retail	$ (1,636,670)	$ (2,751,323)	$ (4,387,993)	6
7	Non-Native Sales Profits Less Fixed Trading Expenses Included in the Pro Forma Test Period Expenses Approved by the Commission in Cause No. 42359	14,747,000	14,747,000	29,494,000	7
8	Amount by Which Actual Net Non-Native Sales Profits Exceed or Are (Less Than) the Net Credit Included in Base Rates 2/	$ (14,747,000)	$ (14,747,000)	$ (29,494,000)	8
9	Sharing Percentage	50%	50%	50%	9
10	Amount Due (To) / From Customers	$ 7,373,500	$ 7,373,500	$ 14,747,000	10

1/ Prior period cost adjustment reflects revisions, and/or true-ups, of MISO, fuel, variable O&M, and EA expenses and/or revenues filed in past Rider 70 proceedings.
2/ Sales profits can be no less than zero for purposes of profit sharing.

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: ______________________ Dated: 09/30/2020
Suzanne E. Sieferman