

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC)
FOR APPROVAL OF A CHANGE IN ITS FUEL)
COST ADJUSTMENT FOR ELECTRIC SERVICE)
AND FOR APPROVAL OF A CHANGE IN ITS FUEL)
COST ADJUSTMENT FOR HIGH PRESSURE) CAUSE NO. 38707-
STEAM SERVICE, IN ACCORDANCE WITH) FAC140
INDIANA CODE §8-1-2-42, INDIANA CODE)
§8-1-2-42.3, AND VARIOUS ORDERS OF THE)
INDIANA UTILITY REGULATORY COMMISSION)

VERIFIED APPLICATION AND AFFIDAVIT FOR APPROVAL OF
A CHANGE(S) IN FUEL COST ADJUSTMENT (ELECTRIC SERVICE)
AND FUEL COST ADJUSTMENT (STEAM SERVICE)

TO THE INDIANA UTILITY REGULATORY COMMISSION:

Duke Energy Indiana, LLC (hereinafter referred to as “Applicant” or “Duke Energy Indiana” or “Company”) respectfully represents and shows unto this Commission:

1. Applicant is a public electric generating utility corporation organized and existing under the laws of the State of Indiana, and has its principal office at 1000 East Main Street, Plainfield, Indiana. It is engaged in rendering electric utility service in the State of Indiana, and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such electric service to the public. It also renders steam service to one customer; namely, International Paper.

Applicant is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act and other laws of the State of Indiana.

2. The names and addresses of the Applicant’s attorneys in this matter are Andrew J. Wells and Liane K. Steffes, 1000 East Main Street, Plainfield, Indiana 46168, who are duly authorized to accept service of papers in this Cause on behalf of Applicant.

3. The following are the applicable procedural dates for this proceeding, as agreed to by the OUCC and approved in Cause No. 45253:

- (i) April 30, 2024 – the date the Company is filing this Verified Application;
- (ii) April 30, 2024 – the date the Company is prefilng testimony and exhibits supporting this Verified Application;
- (iii) June 4, 2024 – the latest date by which the OUCC and any intervenor shall prefile its testimony and exhibits concerning this Verified Application¹;
- (iv) June 10, 2024 – the latest date by which Duke Energy Indiana shall file rebuttal testimony;
- (v) On or after June 17, 2024 – the day on which the Company requests that the evidentiary hearing concerning this Verified Application be held; and
- (vi) June 28, 2024 – the end target date by which the Company requests the issuance of the Commission’s Order concerning this Verified Application.

I. ELECTRIC SERVICE

1. This Application is filed pursuant to the provisions of the Public Service Commission Act (IC 8-1-2-42 (b), (d), (e), (f) and IC 8-1-2-42.3) and pursuant to Orders of the Commission, including the Orders in Cause Nos. 33735-S1, 33735-S2, 37712, 41363, 38707-FAC70, the June 1, 2005 Order in Cause No. 42685 (“MISO Order”), and the Commission’s June 30, 2009 Phase II Order in Cause No. 43426 concerning cost recovery related to the Midcontinent Independent System Operator, Inc.’s (“MISO”) ancillary services market (“Phase II ASM Order”) for the purpose of securing authorization for a change in the fuel cost adjustment applicable to Applicant’s electric rate schedules. Applicant will file with the Commission the required additional showing pursuant to a public hearing held subject to the notice provisions required by IC 8-1-1-8.

¹ The Commission Order in Cause No. 38707 FAC76, dated June 25, 2008, approved an Agreement on Synchronization of FAC and RTO Proceedings in which Duke Energy Indiana agreed to extend the time the Indiana Office of Utility Consumer Counselor (“OUCC”) has to file its audit report and/or other testimony from the statutory 20 days to 35 days from the date Duke Energy Indiana files its testimony. The Agreement also provided that absent unusual circumstances, and assuming the Company prefled testimony for both its FAC and RTO cases within 3 business days of each other, the OUCC agreed not to seek extensions of time to submit its audit reports/testimony for each case beyond the 35 days. With the RTO schedule moving from quarterly to annual filings, as approved in Cause No. 42736 RTO 54, this portion of the Agreement is no longer applicable. However, the Agreement provides that the Company and OUCC will cooperate such that the FAC order can be issued prior to the billing month to which the new cost factor is intended to apply.

2. This Application reflects changes in operations that began on April 1, 2005, resulting from MISO's implementation of energy markets under MISO's Open Access Transmission and Energy Markets Tariff (now known as MISO's Open Access Transmission and Energy and Operating Reserves Tariff and hereinafter "MISO's Tariff"). Such operational changes include purchases and sales of power and dispatch decisions reflecting MISO's day-ahead and real-time energy markets. This Application also reflects changes in operations that began on January 6, 2009, resulting from MISO's implementation of the ancillary service markets ("ASM") under MISO's Tariff. Such operational changes include purchases and sales of ancillary services and dispatch decisions reflecting MISO's day-ahead and real-time ancillary service markets. The recovery of jurisdictional costs requested in this proceeding and the proposed change in Applicant's fuel cost adjustment factor reflect charges and credits incurred by Applicant on behalf of its jurisdictional customers resulting from Applicant's participation in such markets, consistent with the Commission's prior orders regarding participation in and cost recovery of costs incurred due to participation in these markets.

3. This Application is also filed pursuant to the Commission's Order in Cause No. 45253, dated June 29, 2020 (request to change base rates). The Commission's Order in Cause No. 45253 resulted in changes that affect the Company's data filed in the fuel cost adjustment proceedings. For purposes of computing the authorized net operating income for IC 8-1-2-42(d)(3), the changes in authorized jurisdictional operating revenues and expenses, as well as the jurisdictional allocation percentages, were phased-in over the same period of time as the Company's net operating income for the applicable twelve-month period affected by this Order. The authorized net operating income for the twelve-month ended February 29, 2024 period reflected in this filing is based on the Commission's Order in Cause No. 45253 and the associated Step 2 compliance filing. The Commission's Order in Cause No. 45253 also approved Applicant's proposed base cost of fuel to generate electricity and the cost of fuel included in the cost of net purchased electricity of \$0.026955 per kWh. This Application is also filed pursuant to the Commission's July 3, 2002 Order in consolidated Cause Nos. 42061 and 41744-S1 ("ECR Order"), which approved construction work in progress ratemaking treatment for certain qualified pollution control property and clean energy projects, and the Commission's Orders in subsequent ECR proceedings. The value of the Company's plant is also subject to update as a result of (1) the Commission's June 25, 2014 Order in Cause No. 44367, which authorized Duke Energy Indiana to adjust the Company's authorized net operating income to reflect any approved

earnings associated with federally mandated compliance projects (“FMCA”) included in that proceeding and subsequent update proceedings; (2) the Commission’s June 29, 2016 Order in Cause No. 44720, which authorized the Company to adjust its authorized net operating income to reflect approved earnings associated with its investments in transmission, distribution and storage system improvement (“TDSIC”) projects included in that proceeding and subsequent update proceedings; and (3) the Commission’s July 6, 2016 Order in Cause No. 44734, which authorized adjustment to the Company’s authorized net operating income to reflect approved earnings associated with company-owned renewable energy projects (“REP”) included in that proceeding and subsequent update proceedings. As stated above, the Commission’s Order in Cause No. 45253 approved Applicant’s proposed base cost of fuel of \$0.026955 per kWh. Applicant’s cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of February 2024, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was \$0.026801 per kWh as shown on Attachment A, Schedule 9, line 12, column L, attached hereto.

4. Duke Energy Indiana has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. Applicant will file testimony showing these facts prior to the date of hearing herein.

5. Applicant’s testimony will include an explanation of certain financial transactions (*i.e.*, hedging arrangements) that were entered into by the Company on behalf of retail customers. Applicant will show that it entered into such hedging arrangements in order to mitigate the Company’s exposure to price volatility in the bulk power market. Applicant requests that it be allowed to recover the net realized gains or losses associated with its hedging activities incurred on behalf of its native load customers.

6. Applicant’s fuel cost adjustment factor takes into account charges and revenues incurred and received by the Applicant resulting from Applicant’s participation in the energy and ancillary services markets of MISO’s Tariff, as authorized by the Commission in Cause No. 42685 and other Commission orders. In addition, the Commission’s Order in Cause No. 45253 approved the inclusion of fuel-related PJM charges and credits associated with operations of the Company’s Madison Generating Station in the Applicant’s fuel cost adjustment factor subsequent to the effective date of the Order. Pursuant to the Commission’s Phase II ASM

Order, Applicant is authorized to recover certain new or modified MISO charges and credits resulting from its participation in ASM as a cost of fuel in its FAC proceedings and recover and account for Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts in FAC proceedings. Applicant has included MISO and PJM costs and credits in its fuel cost in this proceeding in accordance with the MISO Order, the base rate case order in Cause No. 45253, the Phase II ASM Order and other applicable Orders. Applicant will also provide testimony reporting the monthly average ASM cost distribution amounts paid for Regulation, Spinning, and Supplemental Reserves.

7. Actual increases in Applicant's fuel costs for the 12 months ended February 29, 2024, have not been offset by actual decreases in other operating expenses. Applicant will file testimony and exhibits showing these facts prior to the date of hearing herein.

8. Applicant will file testimony and attachments that will compare actual jurisdictional earnings and expenses for the twelve months ended February 29, 2024, to the phased-in jurisdictional return and expenses authorized by the Commission's Order in Cause No. 45253 and the associated Step 2 compliance filing, subsequent ECR, FMCA, TDSIC, and REP orders as applicable, and the Commission's Order on Remand in Cause No. 45253.

9. The reconciliation of the actual incremental cost of fuel billed retail customers for the period of December 2023 through February 2024, resulted in a negative variance factor (*i.e.*, actual net jurisdictional fuel costs per kilowatt-hour incurred were less than fuel costs billed customers, resulting in a net over-collection of fuel costs).

10. Applicant's net fuel charge in this proceeding is \$0.030266 per kWh; the net fuel charge in Cause No. 38707-FAC139 was \$0.029149 per kWh. The net fuel charge in this proceeding less the base cost of fuel of \$0.026955 will result in a fuel cost adjustment factor of \$0.003311 per kWh applicable to bills rendered by Applicant commencing with the first billing cycle upon the later of the date of approval by the Commission or the first July 2024 billing cycle (see Attachment A, Schedule 1).

Approval of the Company's proposed factor will result in the following estimated bill impacts by customer class:

<u>Customer Class</u>	<u>Estimated Bill Impact^{2 3}</u>
Residential (<i>based on typical customer at 1,000 kWh</i>)	0.9% increase
Commercial (<i>based on three different sets of energy and demand billing determinants</i>)	<1.2% increase
Industrial (<i>based on four different sets of energy and demand billing determinants</i>)	<1.6% increase

11. The books and records of Applicant supporting data filed in this proceeding are kept in accordance with the Uniform System of Accounts for Electric Utilities prescribed by this Commission and are available for inspection and review by the OUCC and this Commission.

WHEREFORE, Applicant respectfully prays that the Indiana Utility Regulatory Commission hold a hearing pursuant to IC 8-1-2-42(a) and (d) and enter an order in this Cause:

- i) authorizing and approving the reconciliation of incremental fuel costs billed to incremental fuel costs actually incurred during the months of December 2023 through February 2024;
- ii) authorizing and approving the recovery of net realized gains and losses attributable to certain hedging activities;
- iii) authorizing and approving the estimated fuel cost adjustment factor of \$0.003311 per kWh to become effective upon the later of the date of approval by the Commission or the first billing cycle of July 2024;
- iv) accepting for filing Applicant's tariff modifications reflecting the estimated fuel cost adjustment factor;
- v) issuing such order within twenty days from the date the Commission receives the OUCC audit report; and

² Estimated bill impact reflects comparison of change between proposed fuel cost rider factor and current factor as compared to total bill (base bill and all other riders) as of April 1, 2024.

³ Bill impacts will vary based on customer usage specifics within each class. For the residential class, usage has been assumed at 1,000 kWh. For the commercial and industrial classes, the percentage reflects the highest estimated bill impact based on bill calculations at representative data points for each group as follows: commercial usage at (a) 3 KW/375kWh, (b) 40 KW/10,000 kWh, and (c) 500 KW/150,000 kWh and industrial usage at (a) 75 KW/15,000 kWh, (b) 75KW/50,000 kWh, (c) 50,000 KW/15,000,000 kWh, and (d) 50,000 KW/25,000,000 kWh.

- vi) making such other and further orders in the proceeding, as the Commission may deem appropriate.

II. STEAM SERVICE

1. This Application is filed pursuant to the Order of the Commission in Cause No. 44087 and pursuant to the provisions of the Public Service Commission Act (IC 8-1-2-42) for the purpose of securing authorization for changes in Applicant's fuel cost adjustment applicable to its rendering of steam service to International Paper.

2. Applicant hereby incorporates by this reference all applicable paragraphs of Part I of this Application.

3. Applicant's proposed factors have been calculated in accordance with the fuel cost adjustment formula contained in the Commission's Order in Cause No. 45740.

4. The calculation showing the proposed fuel cost adjustment is shown on Attachment B, Schedule 1.

5. Applicant's estimated fuel cost for July through September 2024 is 30.8878611 mills per kWh. This amount, when multiplied by the equivalent conversion factor per 1000 pounds of steam of 0.1084, results in a cost factor of \$3.3482441 per thousand pounds of steam. This cost factor, less the base cost of fuel of \$2.921922 per 1000 pounds of steam will result in a fuel cost adjustment factor of \$0.4263221 per 1000 pounds of steam.

A reconciliation of the actual fuel cost adjustment incurred to the estimated fuel cost adjustment billed for the months of December 2023 through February 2024 is shown on Attachment B, Schedule 2. The total reconciliation adjustment of \$(112,3983) will be applied to International Paper's monthly bill for high-pressure steam service in three monthly installments, upon approval of such amount by the Commission.

6. The books and records of Applicant supporting such data and calculation are available for inspection and review by the OUCC and this Commission.

WHEREFORE, Applicant respectfully prays that the Indiana Utility Regulatory Commission hold a hearing and enter an order in this Cause:

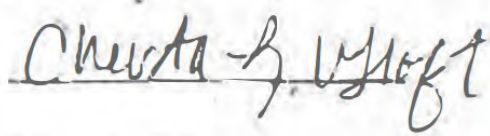
- i) authorizing and approving the changes in its existing fuel cost adjustment charge based upon the costs of fuel shown on said Attachment B, Schedule 1 applicable to Applicant's Commission approved contract for rendering steam service to International Paper;

- ii) authorizing such changes to become effective upon the later of the date of approval by the Commission or the bill rendered to International Paper in July 2024 by Applicant for steam service;
- iii) authorizing and approving the reconciliation adjustments to International Paper as shown on Attachment B, Schedule 2 for the December 2023 through February 2024 timeframe;
- iv) issuing such order within twenty days from the date the Commission receives the OUCC audit report; and
- v) making such other and further orders in the proceeding, as the Commission may deem appropriate and proper.

[SIGNATURE PAGE TO FOLLOW]

Dated this 30th day of April, 2024.

DUKE ENERGY INDIANA, LLC

A handwritten signature in dark ink, appearing to read "Christa L. Graft", written over a horizontal line.

By:

Christa L. Graft, Manager Rates and Regulatory Strategy

A handwritten signature in dark ink, appearing to read "Andrew J. Wells", written over a horizontal line.

Andrew J. Wells, Associate General Counsel

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: Christa L. Graft
Christa L. Graft

Dated: April 30, 2024

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Verified Application and Affidavit delivered electronically to the following:

Lorraine Hitz
Michael Eckert
Office of Utility Consumer Counselor
115 W. Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
LHitz@oucc.in.gov
meckert@oucc.in.gov
infomgt@oucc.in.gov

In addition, copies have been distributed electronically, for informational purposes, to the following:

Financial Solutions Group, Inc.
Attn: Gregory T. Guerrettaz
2680 East Main Street, Suite 223
Plainfield, Indiana 46168
greg@fsgcorp.com
kristen@fsgcorp.com
fsg@fsgcorp.com

Dated this 30th day of April 2024.



Andrew J. Wells, Atty. No. 29545-49
Liane K. Steffes, Atty. No. 31522-41
Duke Energy Business Services LLC
1000 East Main Street
Plainfield, Indiana 46168
(317) 838-2461 (office)
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DUKE ENERGY INDIANA, LLC

Determination of Retail Fuel Cost Adjustment Factor to be
Effective Upon the Order of the Commission
 Based on Estimated Average Fuel Costs
 for the Months of July, August, and September 2024

Line No.	Description	Estimated Month of:			Total	Estimated Three-Month Average	Source	Line No.
		July 2024	August 2024	September 2024				
		(A)	(B)	(C)	(D)	(E)	(F)	
MWh Source:								
1	Steam Generation	1,590,070	1,516,700	1,180,609	4,287,379	1,429,126	Sch.2,Ln 7	1
2	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 8	2
3	Hydro and Solar Generation	43,775	43,561	41,825	129,161	43,054	Sch.2,Ln 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch.2,Ln 10	4
5	Gas Combustion Turbine	641,584	616,418	449,712	1,707,714	569,238	Sch.2,Ln 11	5
6	Integrated Gasification Combined Cycle	378,773	377,893	297,996	1,054,662	351,554	Sch.2,Ln 12	6
7	Purchased Power	285,281	388,011	535,781	1,209,073	403,024	Sch.3,Col.A	7
Less:								
8	Intersystem Sales	-	-	-	-	-	Sch.4,Col.A	8
9	Energy Losses & Company Use	149,606	151,612	130,005	431,223	143,741		9
10	Sales (S)	2,789,877	2,790,971	2,375,918	7,956,766	2,652,255		10
Fuel Cost:								
11	Steam Generation	\$ 47,658,000	\$ 45,120,000	\$ 35,182,000	\$ 127,960,000	\$ 42,653,333	Sch.2,Ln 1	11
12	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 2	12
13	Hydro and Solar Generation	-	-	-	-	-		13
	Other Generation --							
14	Internal Combustion	-	-	-	-	-	Sch.2,Ln 3	14
15	Gas Combustion Turbine	16,603,000	16,519,000	12,560,000	45,682,000	15,227,333	Sch.2,Ln 4	15
16	Integrated Gasification Combined Cycle	10,461,000	10,554,000	7,484,000	28,499,000	9,499,667	Sch.2,Ln 5	16
17	Hedging Position ^{1/}	2,401,000	1,931,000	1,077,000	5,409,000	1,803,000		17
18	Purchased Power	12,954,000	14,789,000	18,827,000	46,570,000	15,523,333	Sch 3, Col. C	18
19	Net MISO Energy Market	2,889,000	2,523,000	678,000	6,090,000	2,030,000		19
20	Net MISO Ancillary Services Market	-	-	-	-	-		20
Less:								
21	Intersystem Sales	-	-	-	-	-	Sch.4,Col.C	21
22	Steam Sales	374,000	370,000	379,000	1,123,000	374,333	Sch.5,Ln 4	22
23	Total Fuel Cost (F)	\$ 92,592,000	\$ 91,066,000	\$ 75,429,000	\$ 259,087,000	\$ 86,362,333		23
24	F / S (Mills Per kWh)					32.562		24
Months to be Reconciled								
		December 2023	January 2024	February 2024	3 Months Total			
25	Monthly Fuel Cost Reconciliation Variance	\$ (685,881)	\$ 5,349,166	\$ (21,668,514)	\$ (17,005,229)	^{2/}	Sch.6s	25
26	Net FAC140 Reconciliation Factor							
	-\$ 17,005,229 / 7,405,082 MWhrs					(2.296)		26
27	Subtotal					30.266		27
28	Less: Base Cost of Fuel Included in Rates					26.955		28
29	Total Fuel Cost Adjustment Factor (Mills Per kWh)					3.311		29

^{1/} These hedging amounts are based on a "marked" current value of the underlying hedging contracts, and therefore their value could fluctuate until settlement when the ultimate gain or loss on the contracts is known.

^{2/} See Attachment A, Schedule 6, Page 3 of 3.

DUKE ENERGY INDIANA, LLC

Determination of the
Estimated Cost of Fuel Consumed (Account 151)
and Net Generation (MWh Output)
for the Months of July, August, and September 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Description	Estimated Month of:				Estimated Three-Month Average	Line No.
		July 2024	August 2024	September 2024	Total		
		(A)	(B)	(C)	(D)	(E)	
<u>Fuel Cost:</u>							
1	Steam Generation	\$ 47,658,000	\$ 45,120,000	\$ 35,182,000	\$ 127,960,000	\$ 42,653,333	1
2	Nuclear Generation	-	-	-	-	-	2
	Other Generation -						
3	Internal Combustion	-	-	-	-	-	3
4	Gas Combustion Turbine	16,603,000	16,519,000	12,560,000	45,682,000	15,227,333	4
5	Integrated Gasification Combined Cycle	10,461,000	10,554,000	7,484,000	28,499,000	9,499,667	5
6	Total Fuel Cost	\$ 74,722,000	\$ 72,193,000	\$ 55,226,000	\$ 202,141,000	\$ 67,380,333	6
<u>Net Generation MWh Output:</u>							
7	Steam Generation	1,590,070	1,516,700	1,180,609	4,287,379	1,429,126	7
8	Nuclear Generation	-	-	-	-	-	8
9	Hydro and Solar Generation	43,775	43,561	41,825	129,161	43,054	9
	Other Generation -						
10	Internal Combustion	-	-	-	-	-	10
11	Gas Combustion Turbine	641,584	616,418	449,712	1,707,714	569,238	11
12	Integrated Gasification Combined Cycle	378,773	377,893	297,996	1,054,662	351,554	12
13	Total Net Generation	2,654,202	2,554,572	1,970,142	7,178,916	2,392,972	13

DUKE ENERGY INDIANA, LLC

**Determination of Estimated
Net Energy Costs of Native Load Purchased Power
for the Months of July, August, and September 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission**

Line No.	Type of Power	MWh Purchased	Demand	Energy Charges			Total	Line No.
				Fuel	Other	Total Energy		
		(A)	(B)	(C)	(D)	(E)	(F)	
	<u>July 2024</u>							
1	Various Purchases ^{1/}	285,281	\$ -	\$ 12,954,000	\$ -	\$ 12,954,000	\$ 12,954,000	1
	<u>August 2024</u>							
2	Various Purchases ^{1/}	388,011	-	14,789,000	-	14,789,000	14,789,000	2
	<u>September 2024</u>							
3	Various Purchases ^{1/}	<u>535,781</u>	<u>-</u>	<u>18,827,000</u>	<u>-</u>	<u>18,827,000</u>	<u>18,827,000</u>	3
4	Total Purchased Power	<u>1,209,073</u>	<u>\$ -</u>	<u>\$ 46,570,000</u>	<u>\$ -</u>	<u>\$ 46,570,000</u>	<u>\$ 46,570,000</u>	4

^{1/} Includes budget amounts related to purchases from Benton County Wind Farm, LLC from PPA approved by the Commission Order in Cause No. 43097, dated December 6, 2006; solar PPAs approved in Cause No. 44578, dated August 19, 2015; and Staunton Solar PPA approved in Cause No. 44953, dated November 21, 2017.

DUKE ENERGY INDIANA, LLC

Determination of Estimated Fuel Costs (Account 151)
Recovered Through Intersystem Sales
for the Months of July, August, and September 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Type of Transaction	MWh Sold (A)	Demand Charge (B)	Energy Charge		Total Energy Charge (E)	Total Charges (F)	Line No.
				Fuel Cost (Accounts 151) (C)	Other Costs (D)			
<u>July 2024</u>								
1	Power Coordination Agreement Sales	_1/	- \$	- \$	- \$	- \$	- \$	1
<u>August 2024</u>								
2	Power Coordination Agreement Sales	_1/	-	-	-	-	-	2
<u>September 2024</u>								
3	Power Coordination Agreement Sales	_1/	-	-	-	-	-	3
4	Total Intersystem Sales		- \$	- \$	- \$	- \$	- \$	4

_1/ Power Coordination Agreements terminated on December 31, 2014.

DUKE ENERGY INDIANA, LLC

Determination of Estimated Equivalent Fuel Costs
Recovered Through the Sale of Steam
for the Months of July, August, and September 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Description	Estimated Month of:			Total	Estimated Three-Month Average	Source	Line No.
		July 2024	August 2024	September 2024				
		(A)	(B)	(C)	(D)	(E)		
1	Total Pounds of Steam Supplied (000s)	111,660	110,465	113,276	335,401	111,800		1
2	Total Equivalent MWh Generated At Cayuga, Other Generating Stations Of the Company and Through Purchased Power Transactions (Note 1)	12,104	11,974	12,279	36,357	12,119		2
3	Equivalent Cost per 1000 lbs Steam (Note 2)	\$ 3.3482441	\$ 3.3482441	\$ 3.3482441				3
4	Fuel Costs Recovered Through the Sale of Steam (Line 1 * Line 3) (Rounded to 000s)	\$ 374,000	\$ 370,000	\$ 379,000	\$ 1,123,000	\$ 374,333		4

Note 1: Equivalent MWh = 0.1084 * Line 1

Note 2: Fuel Cost

Steam Generation	\$ 47,658,000	\$ 45,120,000	\$ 35,182,000	\$ 127,960,000	\$ 42,653,333	Sch. 1, Ln 11
Nuclear Generation	-	-	-	-	-	Sch. 1, Ln 12
Other Generation	-	-	-	-	-	
Internal Combustion	-	-	-	-	-	Sch. 1, Ln 14
Gas Combustion Turbine	16,603,000	16,519,000	12,560,000	45,682,000	15,227,333	Sch. 1, Ln 15
Integrated Gasification Combined Cycle	10,461,000	10,554,000	7,484,000	28,499,000	9,499,667	Sch. 1, Ln 16
Hedging Position	2,401,000	1,931,000	1,077,000	5,409,000	1,803,000	Sch. 1, Ln 17
Purchased Power	12,954,000	14,789,000	18,827,000	46,570,000	15,523,333	Sch. 1, Ln 18
Net MISO Energy Market	2,889,000	2,523,000	678,000	6,090,000	2,030,000	Sch. 1, Ln 19
Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Ln 20
Less:						
Intersystem Sales	-	-	-	-	-	Sch. 1, Ln 21
Total Fuel Costs	\$ 92,966,000	\$ 91,436,000	\$ 75,808,000	\$ 260,210,000	\$ 86,736,666	

MWh

Sales (S)	2,789,877	2,790,971	2,375,918	7,956,766	2,652,255	Sch. 1, Ln 10
Energy Losses & Company Use	149,606	151,612	130,005	431,223	143,741	Sch. 1, Ln 9
Equivalent MWh - Steam Sale	12,104	11,974	12,279	36,357	12,119	Sch. 5, Ln 2

Total MWh (K)	2,951,587	2,954,557	2,518,202	8,424,346	2,808,115	
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F/K (Mills Per MWh)					30.8878611	
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Equivalent Cost per 1000 lbs Steam (Mills Per MWh * 0.1084)					\$ 3.3482441	
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DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for December 2023

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred 1/	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 137	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance (Over) or Under Billing	Line No.
		(A)	(B)	(C)	(D) (Col.C) - (Col.B)	(E)	(F)	(G) (Col. E) - (Col. F)	(H) (Col. D) - (Col. G)	
1	Total Residential	769,390	\$ 20,738,907	\$ 25,048,006	\$ 4,309,099	\$ 5,477,521	\$ (190,151)	\$ 5,667,672	\$ (1,358,573)	1
2	Total Commercial	290,171	7,821,559	9,446,711	1,625,152	(1,067,932)	(71,715)	(996,217)	2,621,369	2
3	Total Industrial	707,419	19,068,480	23,030,499	3,962,019	5,454,422	(174,836)	5,629,258	(1,667,239)	3
4	Total Other	<u>147,672</u>	<u>3,980,499</u>	<u>4,807,561</u>	<u>827,062</u>	<u>1,072,004</u>	<u>(36,496)</u>	<u>1,108,500</u>	<u>(281,438)</u>	4
5	Total Retail kWh Sales Subject to Fuel Adjustment Clause	1,914,652	<u>\$ 51,609,445</u>	<u>\$ 62,332,777</u>	<u>\$ 10,723,332</u>	<u>\$ 10,936,015</u>	<u>\$ (473,198)</u>	<u>\$ 11,409,213</u>	<u>\$ (685,881)</u>	5
6	Retail kWh Sales Not Subject to the Fuel Adjustment Clause	19,883								6
7	kWh Sales for Resale	<u>167,370</u>								7
8	Sales	<u>2,101,905</u>								8

1/ Equal to total fuel cost (Schedule 7, column D), minus retail kwh not subject to fuel adjustment clause (Schedule 6, line 6, column A) x fuel cost - mills per kWh (F/S, Schedule 7, column D).

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for January 2024

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred 1/	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 138	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance (Over) or Under Billing	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
					(Col.C) - (Col.B)			(Col. E) - (Col. F)	(Col. D) - (Col. G)	
1	Total Residential	980,447	\$ 26,427,949	\$ 36,939,413	\$ 10,511,464	\$ 6,502,217	\$ (907,844)	\$ 7,410,061	\$ 3,101,403	1
2	Total Commercial	528,805	14,253,939	19,923,307	5,669,368	3,511,123	(489,647)	4,000,770	1,668,598	2
3	Total Industrial	914,374	24,646,951	34,450,040	9,803,089	8,834,840	(846,664)	9,681,504	121,585	3
4	Total Other	149,708	4,035,379	5,640,413	1,605,034	1,008,832	(138,622)	1,147,454	457,580	4
5	Total Retail kWh Sales Subject to Fuel Adjustment Clause	2,573,334	\$ 69,364,218	\$ 96,953,173	\$ 27,588,955	\$ 19,857,012	\$ (2,382,777)	\$ 22,239,789	\$ 5,349,166	5
6	Retail kWh Sales Not Subject to the Fuel Adjustment Clause	17,090								6
7	kWh Sales for Resale	200,394								7
8	Sales	2,790,818								8

1/ Equal to total fuel cost (Schedule 7, column D), minus retail kwh not subject to fuel adjustment clause (Schedule 6, line 6, column A) x fuel cost - mills per kWh (F/S, Schedule 7, column D).

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for February 2024

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred 1/	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 138	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance (Over) or Under Billing	Line No.
		(A)	(B)	(C)	(D) (Col.C) - (Col.B)	(E)	(F)	(G) (Col. E) - (Col. F)	(H) (Col. D) - (Col. G)	
1	Total Residential	915,807	\$ 24,685,578	\$ 23,167,797	\$ (1,517,781)	\$ 6,076,244	\$ (934,296)	\$ 7,010,540	\$ (8,528,321)	1
2	Total Commercial	510,996	13,773,897	12,927,016	(846,881)	3,402,615	(521,312)	3,923,927	(4,770,808)	2
3	Total Industrial	750,497	20,229,647	18,985,836	(1,243,811)	4,901,058	(765,649)	5,666,707	(6,910,518)	3
4	Total Other	158,324	4,267,623	4,005,231	(262,392)	1,034,955	(161,520)	1,196,475	(1,458,867)	4
5	Total Retail kWh Sales Subject to Fuel Adjustment Clause	2,335,624	\$ 62,956,745	\$ 59,085,880	\$ (3,870,865)	\$ 15,414,872	\$ (2,382,777)	\$ 17,797,649	(21,668,514)	5
6	Retail kWh Sales Not Subject to the Fuel Adjustment Clause	23,467								6
7	kWh Sales for Resale	95,355								7
8	Sales	2,454,446								8
9	Fuel Cost Variance for December 2023 (See Attachment A, Schedule 6, Page 1 of 3, Column H)								(685,881)	9
10	Fuel Cost Variance for January 2024 (See Attachment A, Schedule 6, Page 2 of 3, Column H)								5,349,166	10
11	Total Fuel Cost Variance for the Three (3) Months Ended February 2024								\$ (17,005,229)	11

1/ Equal to total fuel cost (Schedule 7, column D), minus retail kwh not subject to fuel adjustment clause (Schedule 6, line 6, column A) x fuel cost - mills per kWh (F/S, Schedule 7, column D).

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
December 2023

Line No.	Description	Total Actual December 2023 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual December 2023 (D)	Line No.
<u>kWh Sales (000's):</u>						
	Native Load Sales					
	Retail					
1	Residential	769,390			769,390	1
2	Commercial	290,171			290,171	2
3	Industrial	721,093			721,093	3
4	Public Street and Highway Lighting	4,579			4,579	4
5	Other Public Authorities	149,302			149,302	5
6	Billed Retail Sales	1,934,535			1,934,535	6
7	Unbilled Retail Sales	233,236			233,236	7
8	Wholesale Sales	167,370	27,720	139,650	-	8
9	Total Native Load Sales (S)	2,335,141	27,720	139,650	2,167,771	9
<u>Fuel Cost:</u>						
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	\$ 67,797,864	\$ 757,832	\$ 3,850,564	\$ 63,189,468	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	1,861,260	22,095	111,310	1,727,855	11
12	Wind and Solar REC Proceeds 5/	(556,709)	(6,609)	(33,293)	(516,807)	12
13	Prior Period Hedging Adjustment 6/	-	-	-	-	13
14	Prior Period Cost Adjustments 3/	(1,647,564)	35,825	(192,675)	(1,490,714)	14
15	Total Fuel Cost (F)	\$ 67,454,851	\$ 809,143	\$ 3,735,906	\$ 62,909,802	15
16	Fuel Cost - Mills per kWh (F/S)	28.887	29.190	26.752	29.021	16

1/ In accordance with the Commission's June 1, 2005 Order in Cause No. 42685 and pertinent subsequent Commission directives, the Company's total native load fuel cost includes applicable MISO costs which were incurred to serve Duke Energy Indiana's native load customers' energy requirements. This line also includes energy costs for third-party solar PPAs, gas costs and steam revenues for the Purdue CHP plant, payments to customers for excess distributed generation, and costs associated with the Speedway Solar PPA.

2/ Hedging component subtotals follow: LMP hedging total (\$19,145); Gas hedging total \$1,880,405.

3/ Prior Period Adjustment Totals by month: 1) Sep23 S105 (\$606,418); 2) Oct23 S105 (\$652,919); 3) Nov23 S105 (\$388,227).

Prior Period Adjustment WVPA 70 by month: 1) Sep23 S105 \$20,354; 2) Oct23 S105 \$22,895; 3) Nov23 S105 (\$7,424).

Prior Period Adjustment Wholesale Formula Rate by month: 1) Sep23 S105 \$30,524; 2) Oct23 S105 (\$104,962); 3) Nov23 S105 (\$118,237).

4/ Adjustment to native load fuel cost to reflect that certain of the Company's wholesale formula rates customers are billed directly by MISO for the three ASM cost distribution charge types (i.e. regulation, spinning and supplemental) related to their load. Therefore, the full amount of these charge types is directly attributable to the Company's remaining native load customers.

5/ Net proceeds received during the month from the sale of renewable energy credits (RECs) associated with Company's wind and solar PPAs.

6/ Prior Period Hedging Adjustment Totals by Month: 1) Sep23 S105 LMP \$0; 2) Oct23 S105 LMP \$0; 3) Nov23 S105 LMP \$0.

DUKE ENERGY INDIANA, LLC

**Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
January 2024**

Line No.	Description	Total Actual January 2024 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual January 2024 (D)	Line No.
<u>kWh Sales (000's):</u>						
	Native Load Sales					
	Retail					
1	Residential	980,447			980,447	1
2	Commercial	528,805			528,805	2
3	Industrial	928,946			928,946	3
4	Public Street and Highway Lighting	5,077			5,077	4
5	Other Public Authorities	147,149			147,149	5
6	Billed Retail Sales	2,590,424			2,590,424	6
7	Unbilled Retail Sales	(381,268)			(381,268)	7
8	Wholesale Sales	200,394	41,020	159,374	-	8
9	Total Native Load Sales (S)	2,409,550	41,020	159,374	2,209,156	9
<u>Fuel Cost:</u>						
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	\$ 107,952,967	\$ 1,522,288	\$ 5,888,864	\$ 100,541,815	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	(2,368,721)	(40,325)	(156,673)	(2,171,723)	11
12	Wind and Solar REC Proceeds 5/	(721,008)	(12,274)	(47,689)	(661,045)	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	\$ 104,863,238	\$ 1,469,689	\$ 5,684,502	\$ 97,709,047	14
15	Fuel Cost - Mills per kWh (F/S)	43.520	35.829	35.668	44.229	15

1/ In accordance with the Commission's June 1, 2005 Order in Cause No. 42685 and pertinent subsequent Commission directives, the Company's total native load fuel cost includes applicable MISO costs which were incurred to serve Duke Energy Indiana's native load customers' energy requirements. This line also includes energy costs for third-party solar PPAs, gas costs and steam revenues for the Purdue CHP plant, payments to customers for excess distributed generation, and costs associated with the Speedway Solar PPA.

2/ Hedging component subtotals follow: LMP hedging total \$44,383; Gas hedging total (\$2,413,104).

3/ Prior Period Adjustment Totals by month: None.
Prior Period Adjustment WVPA 70 by month: None.
Prior Period Adjustment Wholesale Formula Rate by month: None.

4/ Adjustment to native load fuel cost to reflect that certain of the Company's wholesale formula rates customers are billed directly by MISO for the three ASM cost distribution charge types (i.e. regulation, spinning and supplemental) related to their load. Therefore, the full amount of these charge types is directly attributable to the Company's remaining native load customers.

5/ Net proceeds received during the month from the sale of renewable energy credits (RECs) associated with Company's wind and solar PPAs.

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
February 2024

Line No.	Description	Total Actual February 2024 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual February 2024 (D)	Line No.
<u>kWh Sales (000's):</u>						
	Native Load Sales					
	Retail					
1	Residential	915,807			915,807	1
2	Commercial	510,996			510,996	2
3	Industrial	768,364			768,364	3
4	Public Street and Highway Lighting	5,142			5,142	4
5	Other Public Authorities	158,782			158,782	5
6	Billed Retail Sales	2,359,091			2,359,091	6
7	Unbilled Retail Sales	(223,782)			(223,782)	7
8	Wholesale Sales	95,355	17,570	77,785	-	8
9	Total Native Load Sales (S)	2,230,664	17,570	77,785	2,135,309	9
<u>Fuel Cost:</u>						
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	\$ 59,783,935	\$ 467,972	\$ 2,058,278	\$ 57,257,685	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	3,127,657	24,635	109,064	2,993,958	11
12	Wind and Solar PPA REC Proceeds 5/	(531,942)	(4,190)	(18,549)	(509,203)	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	\$ 62,379,650	\$ 488,417	\$ 2,148,793	\$ 59,742,440	14
15	Fuel Cost - Mills per kWh (F/S)	27.965	27.798	27.625	27.978	15

1/ In accordance with the Commission's June 1, 2005 Order in Cause No. 42685 and pertinent subsequent Commission directives, the Company's total native load fuel cost includes applicable MISO costs which were incurred to serve Duke Energy Indiana's native load customers' energy requirements. This line also includes energy costs for third-party solar PPAs, gas costs and steam revenues for the Purdue CHP plant, payments to customers for excess distributed generation, and costs associated with the Speedway Solar PPA.

2/ Hedging component subtotals follow: LMP hedging total \$72,954; Gas hedging total \$3,054,703.

3/ Prior Period Adjustment Totals by month: None.
Prior Period Adjustment WVPA 70 by month: None.
Prior Period Adjustment Wholesale Formula Rate by month: None.

4/ Adjustment to native load fuel cost to reflect that certain of the Company's wholesale formula rates customers are billed directly by MISO for the three ASM cost distribution charge types (i.e. regulation, spinning and supplemental) related to their load. Therefore, the full amount of these charge types is directly attributable to the Company's remaining native load customers.

5/ Net proceeds received during the month from the sale of renewable energy credits (RECs) associated with Company's wind and solar PPAs.

DUKE ENERGY INDIANA, LLC

Summary of Fuel Costs Incurred to Meet Native Load
Requirements by Week to Be Recovered Via the Fuel Adjustment Clause
for the Months of December 2023, January 2024 and February 2024

Line No.																Line No.		
	DEI Generation Fuel for DEI Native Load 1/			MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/			DEI Generation Total Expense for DEI Native Load			Other MISO Charges and/or Credits Allocated to DEI Native Load 3/	Total DEI Native Load Purchases 4/			Total Via Fuel Adjustment Clause 5/				
	MWh	\$	\$/MWh	MWh	\$	\$/MWh	MWh	\$	\$/MWh	\$	MWh	\$	\$/MWh	MWh	\$		\$/MWh	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)		
December 2023																		
1	01 - 02	75,614.251	2,090,851.18	27.65	75,614.251	189,418.53	2.51	75,614.251	2,280,269.71	30.16	(999,764.12)	67,803.625	2,471,381.58	36.45	143,417.876	3,751,887.17	26.16	1
2	03 - 09	332,611.640	9,288,849.77	27.93	332,611.640	1,552,694.58	4.67	332,611.640	10,841,544.35	32.60	(1,825,145.06)	199,453.512	7,152,339.38	35.86	532,065.152	16,168,738.67	30.39	2
3	10 - 16	362,992.916	10,453,038.73	28.80	362,992.916	686,211.96	1.89	362,992.916	11,139,250.69	30.69	(743,906.07)	186,849.263	6,132,902.34	32.82	549,842.179	16,528,246.96	30.06	3
4	17 - 23	387,651.649	11,081,229.22	28.59	387,651.649	1,132,573.02	2.92	387,651.649	12,213,802.24	31.51	(813,438.64)	156,313.784	5,033,971.18	32.20	543,965.433	16,434,334.78	30.21	4
5	24 - 30	316,841.640	9,005,267.23	28.42	316,841.640	512,477.11	1.62	316,841.640	9,517,744.34	30.04	(102,505.52)	158,279.558	4,120,480.81	26.03	475,121.198	13,535,719.63	28.49	5
6	31 - 31	28,935.966	885,459.49	30.60	28,935.966	59,776.00	2.07	28,935.966	945,235.49	32.67	(307,664.00)	43,194.822	1,059,561.27	24.53	72,130.789	1,697,133.01	23.53	6
7	Subtotals	1,504,648.062	42,804,695.62	28.45	1,504,648.062	4,133,151.20	2.75	1,504,648.062	46,937,846.82	31.20	(4,792,423.41)	811,894.564	25,970,636.55	31.99	2,316,542.627	68,116,060.21	29.40	7
8														WVPA-IMPA Adjustment 6/	(187,952.217)	(5,514,466.65)	29.34	8
9														Native Alloc. Of Gas Pipeline Res. Fee 7/	369,646.05			9
10														Other Fuel Cost Adjustments	-			10
11															2,128,590.410	62,971,239.61	29.58	11
January 2024																		
12	01 - 06	346,878.452	13,241,934.61	38.17	346,878.452	310,696.97	0.90	346,878.452	13,552,631.58	39.07	(1,215,439.78)	150,327.210	5,057,170.91	33.64	497,205.662	17,394,362.71	34.98	12
13	07 - 13	385,066.238	13,409,205.63	34.82	385,066.238	423,468.79	1.10	385,066.238	13,832,674.42	35.92	(822,382.97)	230,065.832	8,289,248.51	36.03	615,132.070	21,299,539.96	34.63	13
14	14 - 20	665,838.707	24,717,681.51	37.12	665,838.707	4,481,402.09	6.73	665,838.707	29,199,083.60	43.85	(5,491,240.32)	112,153.999	12,170,939.26	108.52	777,992.706	35,878,782.54	46.12	14
15	21 - 27	425,541.745	16,333,649.59	38.38	425,541.745	506,004.09	1.19	425,541.745	16,839,653.68	39.57	(495,341.01)	172,940.472	5,925,888.49	34.27	598,482.217	22,270,201.16	37.21	15
16	28 - 31	124,211.769	5,280,436.62	42.51	124,211.769	197,000.54	1.59	124,211.769	5,477,437.16	44.10	(435,727.69)	204,116.571	6,078,548.98	29.78	328,328.340	11,120,258.46	33.87	16
17	Subtotals	1,947,536.911	72,982,907.96	37.47	1,947,536.911	5,918,572.48	3.04	1,947,536.911	78,901,480.44	40.51	(8,460,131.77)	869,604.084	37,521,796.14	43.15	2,817,140.995	107,963,144.82	38.32	17
18														WVPA-IMPA Adjustment 6/	(247,240.007)	(8,779,600.97)	35.51	18
19														Native Alloc. Of Gas Pipeline Res. Fee 7/	795,406.66			19
20														Other Fuel Cost Adjutments	-			20
21															2,569,900.988	99,978,950.51	38.90	21
February 2024																		
22	01 - 03	64,884.206	2,086,751.74	32.16	64,884.206	34,996.98	0.54	64,884.206	2,121,748.72	32.70	(1,173,814.22)	163,280.719	4,458,798.07	27.31	228,164.925	5,406,732.57	23.70	22
23	04 - 10	189,739.094	5,643,906.05	29.75	189,739.094	861,689.75	4.54	189,739.094	6,505,595.80	34.29	(850,697.43)	318,158.409	8,830,063.99	27.75	507,897.503	14,484,962.36	28.52	23
24	11 - 17	240,960.647	6,804,352.85	28.24	240,960.647	183,726.26	0.76	240,960.647	6,988,079.11	29.00	(506,160.80)	299,140.346	8,445,967.30	28.23	540,100.993	14,927,885.61	27.64	24
25	18 - 24	281,898.909	7,736,865.75	27.45	281,898.909	393,106.93	1.39	281,898.909	8,129,972.68	28.84	(544,443.42)	239,943.554	6,383,334.16	26.60	521,842.463	13,968,863.42	26.77	25
26	25 - 29	190,947.943	5,522,325.82	28.92	190,947.943	392,116.70	2.05	190,947.943	5,914,442.52	30.97	(293,623.12)	169,908.254	4,735,002.64	27.87	360,856.198	10,355,822.04	28.70	26
27	Subtotals	968,430.799	27,794,202.21	28.70	968,430.799	1,865,636.62	1.93	968,430.799	29,659,838.83	30.63	(3,368,738.99)	1,190,431.282	32,853,166.15	27.60	2,158,862.082	59,144,266.00	27.40	27
28														WVPA-IMPA Adjustment 6/	(100,076.648)	(2,698,555.36)	26.96	28
29														Native Alloc. Of Gas Pipeline Res. Fee 7/	610,987.42			29
30														Other Fuel Cost Adjutments 8/	-			30
31															2,058,785.434	57,056,698.06	27.71	31

Notes:

The net fuel costs are based on results of the Sumatra computer modeling process using the most current MISO statements available. They will be adjusted in future periods, as needed, based on revised MISO statements and new Sumatra modeling results ("Sumatra adjustments").

1/ Includes the Markland run-of-river hydroelectric generation and Crane solar generation.

2/ Includes the MISO Congestion and Loss components of LMP for generation and purchases allocated to serve native load and offsets to revenue for generating unit off-line auxiliary power (i.e., generation revenues from MISO less corresponding load expense to MISO).

3/ Includes multiple MISO related charges and credits. See Attachment A, Schedule 11 for additional detail.

4/ Includes net purchased power for DEI native load in excess of DEI generation allocated by Sumatra to serve native load (e.g. Benton County Wind PPA, MISO purchased power, and Bilateral purchased power). In accordance with the Commission's July 29, 2020 Order in Cause No. 45253, the purchased power benchmark process was eliminated for periods after the date of the rate order.

5/ Does not include Sumatra adjustments of prior period costs recognized in the current period or third party transmission activity.

6/ Manual exclusion of fuel cost associated with WVPA and IMPA's joint ownership of Gibson unit 5, necessary because Sumatra models and allocates cost to 100% of Gibson 5.

7/ DEI native load allocation of gas pipeline reservation fees. The fees are allocated based on the percentage of generation from pipeline reservation cost assessed units assigned to native load versus total generation output of these units.

DUKE ENERGY INDIANA, LLC

Actual Native Load Cost of Fuel to Generate Electricity and the
Actual Native Load Cost of Fuel Included in the Cost of Purchased Power
March 2023 through February 2024

Line No.	Description	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1	MWh Sales (S)	<u>2,351,797</u>	<u>2,138,922</u>	<u>1,972,822</u>	<u>2,314,637</u>	<u>2,834,919</u>	<u>2,451,238</u>	<u>2,450,053</u>	<u>2,138,217</u>	<u>2,274,756</u>	<u>2,335,141</u>	<u>2,409,550</u>	<u>2,230,664</u>	1
	Fuel Cost (F)													
2	Native Load Fuel Cost	\$ 76,978,531	\$ 53,168,915	\$ 69,180,591	\$ 73,330,344	\$ 91,833,366	\$ 92,778,231	\$ 74,924,698	\$ 71,380,713	\$ 66,978,521	\$ 67,797,864	\$ 107,952,967	\$ 59,783,935	2
3	Realized Hedging Activity	7,507,920	10,246,173	6,460,402	5,243,640	1,211,194	375,518	384,926	78,355	825,442	1,861,260	(2,368,721)	3,127,657	3
4	Other Adjustments	(711,852)	(1,164,080)	(466,000)	(2,074,750)	7,161	(344,640)	(66,918)	-	(31,177)	(556,709)	(721,008)	(531,942)	4
5	Prior Period Cost Adjustments ^{1/}	<u>(1,734,738)</u>	<u>-</u>	<u>-</u>	<u>(3,093,700)</u>	<u>-</u>	<u>-</u>	<u>(2,191,744)</u>	<u>-</u>	<u>-</u>	<u>(1,647,564)</u>	<u>-</u>	<u>-</u>	5
6	Total Fuel Cost (F)	<u>\$ 82,039,861</u>	<u>\$ 62,251,008</u>	<u>\$ 75,174,993</u>	<u>\$ 73,405,534</u>	<u>\$ 93,051,721</u>	<u>\$ 92,809,109</u>	<u>\$ 73,050,962</u>	<u>\$ 71,459,068</u>	<u>\$ 67,772,786</u>	<u>\$ 67,454,851</u>	<u>\$ 104,863,238</u>	<u>\$ 62,379,650</u>	6
7	Fuel Cost Per kWh (Mills) F/S	<u>\$ 34.884</u>	<u>\$ 29.104</u>	<u>\$ 38.105</u>	<u>\$ 31.714</u>	<u>\$ 32.823</u>	<u>\$ 37.862</u>	<u>\$ 29.816</u>	<u>\$ 33.420</u>	<u>\$ 29.793</u>	<u>\$ 28.887</u>	<u>\$ 43.520</u>	<u>\$ 27.965</u>	7
	Fuel Cost Factor Restated Based On Synchronization of Sumatra Adjustments													
8	Remove: Prior Period Sumatra Adjustments Reflected in the Current Month	(1,734,738)	-	-	(3,093,700)	-	-	(2,191,744)	-	-	(1,647,564)	-	-	8
9	Remove: Hedging and Other Fuel Adjustments	6,796,068	9,082,093	5,994,402	3,168,890	1,218,355	30,878	318,008	78,355	794,265	1,304,551	(3,089,729)	2,595,715	9
10	Add: Subsequent Sumatra Adjustments that Pertain to the Month Presented	<u>(1,235,700)</u>	<u>(1,292,185)</u>	<u>(565,815)</u>	<u>(159,115)</u>	<u>(1,016,834)</u>	<u>(1,015,795)</u>	<u>(606,418)</u>	<u>(652,919)</u>	<u>(388,227)</u>	<u>-</u>	<u>-</u>	<u>-</u>	10
11	Restated Total Fuel Costs	<u>\$ 75,742,831</u>	<u>\$ 51,876,730</u>	<u>\$ 68,614,776</u>	<u>\$ 73,171,229</u>	<u>\$ 90,816,532</u>	<u>\$ 91,762,436</u>	<u>\$ 74,318,280</u>	<u>\$ 70,727,794</u>	<u>\$ 66,590,294</u>	<u>\$ 67,797,864</u>	<u>\$ 107,952,967</u>	<u>\$ 59,783,935</u>	11
12	Fuel Cost Factor	<u>32.206</u>	<u>24.254</u>	<u>34.780</u>	<u>31.612</u>	<u>32.035</u>	<u>37.435</u>	<u>30.333</u>	<u>33.078</u>	<u>29.274</u>	<u>29.034</u>	<u>44.802</u>	<u>26.801</u>	12
13	Percentage Variance from Preliminary Fuel Cost (Ln. 6) to Adjusted Fuel Cost, Excluding Hedging and Other Adjustments (Ln. 11)	(7.68 %)	(16.67 %)	(8.73 %)	(0.32 %)	(2.40 %)	(1.13 %)	1.73 %	(1.02 %)	(1.74 %)	0.51 %	2.95 %	(4.16 %)	13

^{1/} Prior period adjustments reflect the allocation of operating company fuel expense and purchased power costs for certain prior months based on the results of the Sumatra model.

DUKE ENERGY INDIANA, LLC

Actual Fuel Cost Per kWh
Compared to Estimated Fuel Cost Per kWh
for the Months of December 2023, January 2024 and February 2024

Line No.	Description	December 2023		January 2024		February 2024		Total		Line No.
		Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
<u>MWh Source:</u>										
	Native Load Sales									
	Retail									
1	Residential	769,390	782,612	980,447	1,064,731	915,807	964,760	2,665,644	2,812,103	1
2	Commercial	290,171	479,873	528,805	509,107	510,996	473,743	1,329,972	1,462,723	2
3	Industrial	721,093	828,437	928,946	848,496	768,364	837,856	2,418,403	2,514,789	3
4	Public Street and Highway Lighting	4,579	4,227	5,077	5,028	5,142	5,033	14,798	14,288	4
5	Other Public Authorities	149,302	144,879	147,149	154,434	158,782	147,261	455,233	446,574	5
6	Total Billed Sales	1,934,535	2,240,028	2,590,424	2,581,796	2,359,091	2,428,653	6,884,050	7,250,477	6
7	Unbilled Retail Sales	233,236	125,078	(381,268)	(99,339)	(223,782)	(134,219)	(371,814)	(108,480)	7
8	Wholesale Sales	167,370	329,222	200,394	256,310	95,355	238,382	463,119	823,914	8
9	Total Native Load Sales (S)	2,335,141	2,694,328	2,409,550	2,738,767	2,230,664	2,532,816	6,975,355	7,965,911	9
<u>Fuel Cost:</u>										
10	Native Load Fuel Cost	\$ 67,797,864	\$ 95,183,000	\$ 107,952,967	\$ 95,414,000	\$ 59,783,935	\$ 87,800,000	235,534,766	278,397,000	10
11	Hedging Activity and Other Adjustments	1,304,551	(15,000)	(3,089,729)	409,000	2,595,715	373,000	810,537	767,000	11
12	Total Fuel Cost	69,102,415	95,168,000	104,863,238	95,823,000	62,379,650	88,173,000	236,345,303	279,164,000	12
13	Fuel Cost - Mills Per kWh Before Prior Period Adjustment (F/S)	\$ 29.592	\$ 35.322	\$ 43.520	\$ 34.988	\$ 27.965	\$ 34.812	\$ 33.883	\$ 35.045	13
14	Percentage (%) Actual is Over (Under) Estimate Before Prior Period Adjustments	(16.22 %)		24.39 %		(19.67 %)		(3.32 %)		14
15	Prior Period Cost Adjustments	(1,647,564)	-	-	-	-	-	(1,647,564)	-	15
16	Total Fuel Cost (F)	\$ 67,454,851	\$ 95,168,000	\$ 104,863,238	\$ 95,823,000	\$ 62,379,650	\$ 88,173,000	\$ 234,697,739	\$ 279,164,000	16
17	Fuel Cost - Mills Per kWh After Prior Period Adjustment (F/S)	\$ 28.887	\$ 35.322	\$ 43.520	\$ 34.988	\$ 27.965	\$ 34.812	\$ 33.647	\$ 35.045	17
18	Percentage (%) Actual is Over (Under) Estimate After Prior Period Adjustments	(18.22 %)		24.39 %		(19.67 %)		(3.99 %)		18

DUKE ENERGY INDIANA, LLC**Other MISO/PJM Charges/(Credits) Allocated to Native Load Customers**

Line No.	MISO/PJM Charge Description	cXL - MISO/PJM Charge Description	December-23	January-24	February-24	Line No.
1	DA Congestion Rebate on Carve-Out Grandfathered Agrmnts	DA Cong Rebate CO	\$ -	\$ -	\$ -	1
2	DA Congestion Rebate on Option B Grandfathered Agrmnts	DA Cong Rebate Opt B	\$ -	\$ -	\$ -	2
3	DA Financial Bilateral Transaction Congestion Amount	DA Fin Bilateral Con	\$ -	\$ -	\$ -	3
4	DA Financial Bilateral Transaction Loss Amount	DA Fin Bilateral Los	\$ -	\$ -	\$ -	4
5	DA Losses Rebate on Carve-Out Grandfathered Agrmnts	DA Loss Rebate CO	\$ -	\$ -	\$ -	5
6	DA Losses Rebate on Option B Grandfathered Agrmnts	DA Loss Rebate Opt B	\$ -	\$ -	\$ -	6
7	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO DA RSG MKWHL	\$ (12,196.80)	\$ (12,348.82)	\$ (5,491.04)	7
8	DA Virtual Energy Amount	DA Virtual	\$ -	\$ -	\$ -	8
9	FTR Hourly Allocation Amount	FTR	\$ (2,142,753.28)	\$ (5,276,709.36)	\$ (250,587.68)	9
10	FTR Monthly Allocation Amount	MISO FTR MTH ALLOC	\$ (31,436.81)	\$ (135,933.30)	\$ (13,153.97)	10
11	FTR Transaction Amount	MISO FTR Transaction	\$ -	\$ -	\$ -	11
12	FTR Yearly Allocation Amount	MISO FTR YRLY ALLOC	\$ (258,219.50)	\$ -	\$ -	12
13	RT Congestion Rebate on Carve-Out Grandfathered Agrmnts	RT Cong Rebate CO	\$ -	\$ -	\$ -	13
14	RT Congestion Rebate on Option B Grandfathered Agrmnts	RT Cong Rebate Opt B	\$ -	\$ -	\$ -	14
15	RT Distribution of Losses Amount	MISO RT LOSSES	\$ (825,395.27)	\$ (1,536,078.19)	\$ (662,534.83)	15
16	RT Financial Bilateral Transaction Congestion Amount	RT Fin Bilateral Con	\$ -	\$ -	\$ -	16
17	RT Financial Bilateral Transaction Loss Amount	RT Fin Bilateral Los	\$ -	\$ -	\$ -	17
18	RT Losses Rebate on Carve-Out Grandfathered Agrmnts	RT Loss Rebate CO	\$ -	\$ -	\$ -	18
19	RT Loss Rebate on Option B Grandfathered Agrmnts	RT Loss Rebate Opt B	\$ -	\$ -	\$ -	19
20	RT Net Inadvertent Distribution Amount	MISO RT NAD	\$ (60,614.17)	\$ (31,269.21)	\$ (12,248.96)	20
21	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO RT RSG MKWHL	\$ (1,897.62)	\$ (102,245.20)	\$ (1,441.55)	21
22	Contingency Reserve Deployment Failure Charge Uplift Amount	RT Contingency Reserve Deployment Failure Charge Uplift Amount	\$ -	\$ -	\$ -	22
23	RT Virtual Energy Amount	RT Virtual	\$ -	\$ -	\$ -	23
24	GFA (part of DA and RT Asset Energy)	GFA (part of DA and RT Asset Energy)	\$ -	\$ -	\$ -	24
25	FTR Shortfall	MISO FTR Shortfall	\$ 99,543.07	\$ 393,943.98	\$ 13,153.58	25
26	RNU CRDFC Uplift Component	RNU CRDFC Uplift Component	\$ (422.31)	\$ (632.97)	\$ (140.42)	26
27	FTR Full Funding Guarantee Amount	MISO FTR Full Fd Guar	\$ 190,113.49	\$ (258,010.26)	\$ -	27
28	FTR Guarantee Uplift Amount	MISO FTR Guar Uplift	\$ (169,623.59)	\$ 270,739.63	\$ -	28
29	Auction Revenue Rights Stage 2 Distribution Amount	MISO FTR ARR Stage 2	\$ (312,673.04)	\$ (311,420.19)	\$ (313,678.18)	29
30	RT Price Volatility Make Whole Payment	MISO RT VOL MKWHL	\$ (502,576.81)	\$ (1,131,501.02)	\$ (1,159,277.04)	30
31	DA Revenue Sufficiency Guarantee Distribution Amount	MISO DA RSG Dist Amt	\$ 45,700.46	\$ 86,196.52	\$ 51,238.50	31
32	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	MISO RT RSG 1st Pass	\$ 11,909.72	\$ 152,149.49	\$ 7,710.08	32
33	Net Regulation Adjustment Amount	MISO Net Reg Adj Amt	\$ (4,525.56)	\$ 8,221.25	\$ 6,328.25	33
34	Regulation Cost Distribution Amount	MISO Reg Dist	\$ 69,641.00	\$ 54,675.26	\$ 68,799.05	34
35	Spinning Reserve Cost Distribution Amount	MISO Spin Dist	\$ 70,696.90	\$ 71,237.79	\$ 54,611.62	35
36	Supplemental Reserve Cost Distribution Amount	MISO Supp Dist	\$ 6,139.10	\$ 11,818.26	\$ 8,013.48	36
37	RT Excessive/Deficient Energy Deployment Charge Amount	MISO Reg Penalty	\$ 36,030.98	\$ 135,374.08	\$ 18,318.82	37
38	DA Regulation Amount	DA Regulation	\$ (163,608.87)	\$ (225,280.16)	\$ (260,171.33)	38
39	DA Spinning Reserve Amount	DA Spinning	\$ (105,809.34)	\$ (108,547.84)	\$ (69,872.74)	39
40	RT Regulation Amount	MISO RT Regulation	\$ (55,389.38)	\$ (58,702.09)	\$ (20,570.66)	40
41	RT Spinning Reserve Amount	MISO RT Spinning	\$ (11,747.46)	\$ (13,233.68)	\$ (1,596.99)	41
42	RT Supplemental Reserve Amount	MISO RT Supplemental	\$ (0.21)	\$ (914.20)	\$ -	42
43	DA Supplemental Reserve Amount	DA Supplemental	\$ -	\$ (479.52)	\$ -	43
44	Auction Revenue Rights Infeasible Uplift Amount	MISO infesbl ARR UP	\$ 47,668.23	\$ 47,477.23	\$ 47,821.47	44
45	Contingency Reserve Deployment Failure Charge Amount	MISO Res Dep Penalty	\$ -	\$ -	\$ -	45
46	FTR Monthly Transaction Amount	MISO FTR MTH TX AMT	\$ 40,624.74	\$ 40,594.21	\$ (175,351.41)	46
47	FTR Annual Transaction Amount	MISO FTR YRLY TX AMT	\$ 3,897,331.75	\$ 3,881,715.60	\$ 3,909,860.39	47
48	Auction Revenue Rights Transaction Amount	MISO ARR Revenues	\$ (4,541,420.32)	\$ (4,523,223.37)	\$ (4,556,019.49)	48
49	MISO DR Alloc Uplift	MISO DR Alloc Uplift	\$ -	\$ -	\$ -	49
50	MISO Misc Round Adj	MISO Misc/Round Adj	\$ (18,461.61)	\$ (561.48)	\$ (3,122.48)	50
51	Internal Charge Type Related to MISO RT Regulation	MISO RT MIL MWP	\$ (7,709.98)	\$ (15,415.03)	\$ (12,034.22)	51
52	Internal Charge Type Related to MISO RT Regulation	MISO Reg MIL UNDP	\$ 21,546.57	\$ 43,251.58	\$ 31,519.27	52
53	MISO Disputed Amount	MISO Disputed Amount	\$ -	\$ -	\$ -	53
54	RT Ramp Capability	MISO RT Ramp Cpbly	\$ (1,537.80)	\$ (1,110.74)	\$ (2,443.92)	54
55	DA Ramp Capability	DA Ramp Capability	\$ (9,149.96)	\$ (12,701.06)	\$ (11,216.23)	55
56	Madison PJM Charges	Madison PJM Charges	\$ (81,295.14)	\$ (21,846.04)	\$ (51,222.13)	56
57	Battery Charges	Native Battery MISO Charges	\$ (76.59)	\$ (1,067.71)	\$ 938.52	57
58	Short-Term Reserve Cost Distribution Amount	MISO ST Res Dist Amt	\$ 14,024.90	\$ 315,285.24	\$ 14,980.63	58
59	Real-Time Short-Term Reserve Amount	MISO ST Reserve Amt	\$ (1,576.85)	\$ (10,350.15)	\$ (1,846.88)	59
60	Day-Ahead Short-Term Reserve Amount	DA ST Reserve	\$ (23,276.05)	\$ (183,230.30)	\$ (18,010.50)	60
61	MISO Excess Congestion	MISO Excess Congestion	\$ -	\$ -	\$ -	61
62	Net Charges/(Credits) to Duke Energy Indiana (Attachment A, Schedule 8, column J, lines 7, 17 and 27)		\$ (4,792,423.41)	\$ (8,460,131.77)	\$ (3,368,738.99)	62

DUKE ENERGY INDIANA, LLC

Determination of International Paper
Fuel Cost Adjustment Factor Based on Estimated Average Fuel Costs
for the Months of July, August, and September 2024

Line No.	Description	Estimated Month of:			Total	Estimated Three-Month Average	Source ATTACHMENT A	Line No.
		July 2024	August 2024	September 2024				
		(A)	(B)	(C)	(D)	(E)		
	MWh Source:							
1	Steam Generation	1,590,070	1,516,700	1,180,609	4,287,379	1,429,126	Sch. 2, Line 7	1
2	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 8	2
3	Hydro and Solar Generation	43,775	43,561	41,825	129,161	43,054	Sch. 2, Line 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch. 2, Line 10	4
5	Gas Combustion Turbine	641,584	616,418	449,712	1,707,714	569,238	Sch. 2, Line 11	5
6	Integrated Gasification Combined Cycle	378,773	377,893	297,996	1,054,662	351,554	Sch. 2, Line 12	6
7	Purchased Power	285,281	388,011	535,781	1,209,073	403,024	Sch. 3, Col. A	7
8	Equivalent kWh - Steam Sale	12,104	11,974	12,279	36,357	12,119	Sch. 5, Line 2	8
	Less:							
9	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. A	9
10	Total MWh (K)	2,951,587	2,954,557	2,518,202	8,424,346	2,808,115		10
	Fuel Cost:							
11	Steam Generation	\$ 47,658,000	\$ 45,120,000	\$ 35,182,000	\$ 127,960,000	\$ 42,653,333	Sch. 2, Line 1	11
12	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 2	12
13	Hydro and Solar Generation	-	-	-	-	-		13
	Other Generation --							
14	Internal Combustion	-	-	-	-	-	Sch. 2, Line 3	14
15	Gas Combustion Turbine	16,603,000	16,519,000	12,560,000	45,682,000	15,227,333	Sch. 2, Line 4	15
16	Integrated Gasification Combined Cycle	10,461,000	10,554,000	7,484,000	28,499,000	9,499,667	Sch. 2, Line 5	16
17	Hedging Position	2,401,000	1,931,000	1,077,000	5,409,000	1,803,000	Sch. 1, Line 17	17
18	Purchased Power	12,954,000	14,789,000	18,827,000	46,570,000	15,523,333	Sch. 3, Col. C	18
19	Net MISO Energy Market	2,889,000	2,523,000	678,000	6,090,000	2,030,000	Sch. 1, Line 19	19
20	Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Line 20	20
	Less:							
21	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. C	21
22	Total Fuel Cost (F)	\$ 92,966,000	\$ 91,436,000	\$ 75,808,000	\$ 260,210,000	\$ 86,736,666		22
23	F / K (Mills Per MWh)					30.8878611		23
24	Equivalent Cost Per 1000 lbs Steam (Line 23 * 0.1084)					3.3482441		24
25	Less: Base Cost of Fuel Included in Rates Per 1000 lbs Steam					2.9219220		25
26	Fuel Cost Adjustment Factor Per 1000 lbs Steam					0.4263221		26

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Fuel Cost Incurred to Fuel Cost Billed
to International Paper
For the Months of December 2023 through February 2024

Line No.	Month	Steam Supplied (lbs.)	Actual Fuel Cost Adjustment Factor <u>1/</u>	Estimated Fuel Cost Adjustment Factor	Variance	Reconciliation Amount	Line No.
1	December 2023	124,884,497	(0.0062135)	0.6118706	(0.6180841)	\$ (77,189)	1
2	January 2024	130,359,624	0.8858552	0.6381516	0.2477036	32,291	2
3	February 2024	108,675,621	0.0170345	0.6381516	(0.6211171)	(67,500)	3
4	TOTAL RECONCILIATION					\$ (112,398)	4

1/ Detailed below are determinants of the actual cost figures represented above.

	December 2023	January 2024	February 2024
MWh Sales (K)	2,349,898	2,793,737	2,216,426
Fuel Cost (F)	\$ 63,206,805	\$ 98,135,867	\$ 60,092,063
F/K (Mills Per kWh)	26.8976802	35.1270957	27.1121450
Equivalent Cost per 1000lbs Steam	2.9157085	3.8077772	2.9389565
Less: Base Cost of Fuel Included in Rates	<u>2.9219220</u>	<u>2.9219220</u>	<u>2.9219220</u>
Fuel Cost Charge Factor (Per 1000lbs Steam)	(0.0062135)	0.8858552	0.0170345