FILED
November 7, 2022
INDIANA UTILITY
REGULATORY COMMISSION

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 STEAM SERVICE, IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3, AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	)))))))))	**CAUSE NO. 38707-FAC134**

AMENDED 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.[1] 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.

OFFICIAL EXHIBITS

IURC
PETITIONER'S
EXHIBIT NO. 9
12-19-22
DATE
REPORTER

[1] International Paper acquired Temple-Inland's corrugated packaging business on February 13, 2012.

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

(i) October 31, 2022 – the date the Company is filing this Verified Application;

(ii) October 31, 2022 – the date the Company is prefiling testimony and exhibits supporting this Verified Application;

(iii) December 5, 2022 – the latest date by which the OUCC and any intervenor shall prefile its testimony and exhibits concerning this Verified Application[2];

(iv) December 12, 2022 – the latest date by which Duke Energy Indiana shall file rebuttal testimony

(v) On or after December 14, 2022 – the day on which the Company requests that the evidentiary hearing concerning this Verified Application be held; and

(vi) December 30, 2022 – 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.

[2] 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 prefiled 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 Indiana Code 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 August 2022 period reflected in this filing is based on the Commission's Order in Cause No. 45253 Step 2. 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 ("CWIP Order"), which approved construction work in progress ("CWIP") ratemaking treatment for certain qualified pollution control property and the Commission's Orders in subsequent CWIP related proceedings, including the update approved by the Commission on January 12, 2022, in Cause No. 42061-ECR36. 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, including subsequent update proceedings, 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 ("TDSIC") projects; 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 August 2022, 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 $0.061757 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 costs and credits in its fuel cost in this proceeding in accordance with the MISO Order, 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 August 31, 2022, 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 (12) months ended August 31, 2022, to the phased-in jurisdictional return and expenses authorized by the Commission in its Order in Cause No. 45253 Step 2, and subsequent CWIP, FMCA, TDSIC, and REP orders, as applicable.

9. The reconciliation of the actual incremental cost of fuel billed retail customers for the three (3) months ended August 31, 2022, resulted in a positive variance factor (*i.e.,* actual net jurisdictional fuel costs per kilowatt-hour incurred were more than fuel costs billed customers, resulting in a net under-collection of fuel costs).

10. Applicant's net fuel charge in this proceeding is $0.063103 per kWh; the net fuel charge in Cause No. 38707-FAC133 was $0.072903 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 $0.036148 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 January 2023 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:

Customer Class	Estimated Bill Impact[3] [4]
Residential *(based on typical customer at 1,000 kWh)*	5.5% decrease
Commercial *(based on three different sets of energy and demand billing determinants)*	>4.4% decrease
Industrial *(based on four different sets of energy and demand billing determinants)*	>6.4% decrease

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 June through August 2022;

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 $0.036148 per kWh to become effective upon the later of the date of approval by the Commission or the first billing cycle of January 2023;

iv) accepting for filing Applicant's tariff modifications reflecting the estimated fuel cost adjustment factor;

v) issuing such order within twenty (20) days from the date the Commission receives the OUCC audit report; and

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[3] 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 October 1, 2022.

[4] 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. 44087.

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

5. Applicant's estimated fuel cost for January through March 2023 is 41.2440518 mills per kWh. This amount, when multiplied by the equivalent conversion factor per 1000 pounds of steam of .1084, results in a cost factor of $4.4708552 per thousand pounds of steam. This cost factor, less the base cost of fuel of $1.5890079 per 1000 pounds of steam will result in a fuel cost adjustment factor of $2.8818473 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 June through August 2022 is shown on Attachment B, Schedule 2. The total reconciliation adjustment of $386,606 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 January 2023 by Applicant for steam service;

iii) authorizing and approving the reconciliation adjustments to International Paper as shown on Attachment B, Schedule 2 for the June through August 2022 timeframe;

iv) issuing such order within twenty (20) 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 7th day of November 2022.

DUKE ENERGY INDIANA, LLC

By: ______________________________

Suzanne E. Sieferman, Director Rates and Regulatory Planning

____

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: ______________________ Dated: 11/7/2022
Suzanne E. Sieferman

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

Dated this 7th day of November 2022.

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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ATTACHMENT A
SCHEDULE 1

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 January, February, and March 2023

Line No.	Description	Estimated Month of: January 2023 (A)	February 2023 (B)	March 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Source (F)	Line No.
	MWh Source:							
1	Steam Generation	2,136,699	1,954,027	1,726,210	5,816,936	1,938,979	Sch.2,Ln 7	1
2	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 8	2
3	Hydro and Solar Generation	41,802	38,194	42,761	122,757	40,919	Sch.2,Ln 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch.2,Ln 10	4
5	Gas Combustion Turbine	263,517	258,502	285,990	808,009	269,336	Sch.2,Ln 11	5
6	Integrated Gasification Combined Cycle	449,376	403,301	277,877	1,130,554	376,851	Sch.2,Ln 12	6
7	Purchased Power	29,093	27,970	300,180	357,243	119,081	Sch.3,Col.A	7
	Less:							
8	Intersystem Sales	-	-	-	-	-	Sch.4,Col.A	8
9	Energy Losses & Company Use	148,164	136,388	131,428	415,980	138,660		9
10	Sales (S)	2,772,323	2,545,606	2,501,590	7,819,519	2,606,506		10
	Fuel Cost:							
11	Steam Generation	$ 67,292,000	$ 64,755,000	$ 60,479,000	$ 192,526,000	$ 64,175,334	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	18,682,000	17,361,000	16,185,000	52,228,000	17,409,333	Sch.2,Ln 4	15
16	Integrated Gasification Combined Cycle	20,205,000	19,237,000	13,599,000	53,041,000	17,680,333	Sch.2,Ln 5	16
17	Hedging Position 1/	936,588	2,171,540	1,655,245	4,763,373	1,587,791		17
18	Purchased Power	1,916,000	1,836,000	22,354,000	26,106,000	8,702,000	Sch 3, Col. C	18
19	Net MISO Energy Market	3,824,000	6,296,000	2,692,000	12,812,000	4,270,667		19
20	Net MISO Ancillary Services Market	-	-	-	-	-		20
	Less:							
21	Intersystem Sales	-	-	-	-	-	Sch.4,Col.C	21
22	Steam Sales	635,000	590,000	587,000	1,812,000	604,000	Sch.5,Ln 4	22
23	Total Fuel Cost (F)	$ 112,220,588	$ 111,066,540	$ 116,377,245	$ 339,664,373	$ 113,221,458		23
24	F / S (Mills Per kWh)					43.438		24
	Months to be Reconciled	June 2022	July 2022	August 2022	3 Months Total			
25	Monthly Fuel Cost Reconciliation Variance	$ 39,619,378	$ 19,491,417	$ 28,865,260	$ 87,976,055 2/		Sch.6s	25
26	Net FAC134 Reconciliation Factor $ 87,976,055 / 7,090,709 MWhrs					12.407		26
27	Remaining FAC133 Reconciliation Amount to be Included in Current Proceeding $ 51,464,331 / 7,090,709 MWhrs					7.258		27
28	Subtotal					63.103		28
29	Less: Base Cost of Fuel Included in Rates					26.955		29
30	Total Fuel Cost Adjustment Factor (Mills Per kWh)					36.148		30

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 January, February, and March 2023
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission**

Line No.	Description	Estimated Month of: January 2023 (A)	February 2023 (B)	March 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Line No.
	Fuel Cost:						
1	Steam Generation	$ 67,292,000	$ 64,755,000	$ 60,479,000	$ 192,526,000	$ 64,175,334	1
2	Nuclear Generation	-	-	-	-	-	2
	Other Generation -						
3	Internal Combustion	-	-	-	-	-	3
4	Gas Combustion Turbine	18,682,000	17,361,000	16,185,000	52,228,000	17,409,333	4
5	Integrated Gasification Combined Cycle	20,205,000	19,237,000	13,599,000	53,041,000	17,680,333	5
6	Total Fuel Cost	$ 106,179,000	$ 101,353,000	$ 90,263,000	$ 297,795,000	$ 99,265,000	6
	Net Generation MWh Output:						
7	Steam Generation	2,136,699	1,954,027	1,726,210	5,816,936	1,938,979	7
8	Nuclear Generation	-	-	-	-	-	8
9	Hydro and Solar Generation	41,802	38,194	42,761	122,757	40,919	9
	Other Generation -						
10	Internal Combustion	-	-	-	-	-	10
11	Gas Combustion Turbine	263,517	258,502	285,990	808,009	269,336	11
12	Integrated Gasification Combined Cycle	449,376	403,301	277,877	1,130,554	376,851	12
13	Total Net Generation	2,891,394	2,654,024	2,332,838	7,878,256	2,626,085	13

DUKE ENERGY INDIANA, LLC

Determination of Estimated
Net Energy Costs of Native Load Purchased Power
for the Months of January, February, and March 2023
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: Fuel	Energy Charges: Other	Energy Charges: Total Energy	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	
	January 2023							
1	Various Purchases 1/	29,093	$ -	$ 1,916,000	$ -	$ 1,916,000	$ 1,916,000	1
	February 2023							
2	Various Purchases 1/	27,970	-	1,836,000	-	1,836,000	1,836,000	2
	March 2023							
3	Various Purchases 1/	300,180	-	22,354,000	-	22,354,000	22,354,000	3
4	Total Purchased Power	357,243	$ -	$ 26,106,000	$ -	$ 26,106,000	$ 26,106,000	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 PPA's 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 January, February, and March 2023
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Type of Transaction		MWh Sold	Demand Charge	Energy Charge: Fuel Cost (Accounts 151)	Energy Charge: Other Costs	Energy Charge: Total Energy Charge	Total Charges	Line No.
			(A)	(B)	(C)	(D)	(E)	(F)	
	January 2023								
1	Power Coordination Agreement Sales	_1/	-	$ -	$ -	$ -	$ -	$ -	1
	February 2023								
2	Power Coordination Agreement Sales	_1/	-	-	-	-	-	-	2
	March 2023								
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 January, February, and March 2023
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission**

Line No.	Description	Estimated Month of: January 2023 (A)	February 2023 (B)	March 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Source	Line No.
1	Total Pounds of Steam Supplied (000's)	141,944	131,878	131,239	405,061	135,020		1
2	Total Equivalent kWh Generated (000's) At Cayuga, Other Generating Stations Of the Company and Through Purchased Power Transactions (Note 1)	15,387	14,296	14,226	43,909	14,637		2
3	Equivalent Cost per 1000 lbs Steam (Note 2)	4.4708552	4.4708552	4.4708552				3
4	Fuel Costs Recovered Through the Sale of Steam (Line 1 * Line 3) (Rounded to 000's)	$ 635,000	$ 590,000	$ 587,000	$ 1,812,000	$ 604,000		4

Note 1: Equivalent MWh = 0.1084 * Line 1

Note 2: Fuel Cost

Description	January 2023 (A)	February 2023 (B)	March 2023 (C)	Total (D)	Three-Month Average (E)	Source
Steam Generation	$ 67,292,000	$ 64,755,000	$ 60,479,000	$ 192,526,000	$ 64,175,334	Sch. 2, Ln 1
Nuclear Generation	-	-	-	-	-	Sch. 2, Ln 2
Other Generation						
Internal Combustion	-	-	-	-	-	Sch. 2, Ln 3
Gas Combustion Turbine	18,682,000	17,361,000	16,185,000	52,228,000	17,409,333	Sch. 2, Ln 4
Integrated Gasification Combined Cycle	20,205,000	19,237,000	13,599,000	53,041,000	17,680,333	Sch. 2, Ln 5
Hedging Position	936,588	2,171,540	1,655,245	4,763,373	1,587,791	Sch. 1, Ln 17
Purchased Power	1,916,000	1,836,000	22,354,000	26,106,000	8,702,000	Sch. 1, Ln 18
Net MISO Energy Market	3,824,000	6,296,000	2,692,000	12,812,000	4,270,667	Sch. 1, Ln 19
Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Ln 20
Less:						
Intersystem Sales	-	-	-	-	-	Sch. 4, Col. C
Total Fuel Costs	$ 112,855,588	$ 111,656,540	$ 116,964,245	$ 341,476,373	$ 113,825,458	
MWh						
Sales (S)	2,772,323	2,545,606	2,501,590	7,819,519	2,606,506	Sch. 1, Ln 10
Energy Losses & Company Use	148,164	136,388	131,428	415,980	138,660	Sch. 1, Ln 9
Equivalent kWh - Steam Sale	15,387	14,296	14,226	43,909	14,637	Sch. 5, Ln 2
Total kWh (K)	2,935,874	2,696,290	2,647,244	8,279,408	2,759,803	
F/K (Mills Per kWh)					41.2440518	
Equivalent Cost per 1000 lbs Steam (Mills Per kWh * 0.1084)					$ 4.4708552	

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the June 2022 Billing Cycle

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred - 49.679 Mills/kWh (See Sch. 7)	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 131	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	734,023	$ 19,785,589	$ 36,465,529	$ 16,679,940	$ 8,547,616	$ 4,104,138	$ 4,443,478	$ 12,236,462	1
2	Total Commercial	751,696	20,261,966	37,343,505	17,081,539	$ 8,496,277	4,202,953	4,293,324	12,788,215	2
3	Total Industrial	710,610	19,154,493	35,302,394	16,147,901	$ 8,459,183	3,973,229	4,485,954	11,661,947	3
4	Total Other	186,349	5,023,037	9,257,632	4,234,595	2,343,773	1,041,932	1,301,841	2,932,754	4
5	Total Retail kWh Sales Subject to Fuel Clause Adjustment	2,382,678	$ 64,225,085	$ 118,369,060	$ 54,143,975	$ 27,846,849	$ 13,322,252	$ 14,524,597	$ 39,619,378	5
6	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	35,800								6
7	kWh Sales for Resale	295,948								7
8	Sales	2,714,426								8

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the July 2022 Billing Cycle

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred - 56.681 Mills/kWh (See Sch. 7)	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 131 and 132	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	872,818	$ 23,526,809	$ 49,472,197	$ 25,945,388	$ 29,929,279	$ 12,502,506	$ 17,426,773	$ 8,518,615	1
2	Total Commercial	464,380	12,517,363	26,321,523	13,804,160	17,545,779	6,651,918	10,893,861	2,910,299	2
3	Total Industrial	668,952	18,031,601	37,916,868	19,885,267	23,323,773	9,582,268	13,741,505	6,143,762	3
4	Total Other	148,562	4,004,489	8,420,643	4,416,154	4,625,459	2,128,046	2,497,413	1,918,741	4
5	Total Retail kWh Sales Subject to Fuel Clause Adjustment	2,154,712	$ 58,080,262	$ 122,131,231	$ 64,050,969	$ 75,424,290	$ 30,864,738	$ 44,559,552	$ 19,491,417	5
6	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	(41,396)								6
7	kWh Sales for Resale	302,835								7
8	Sales	2,416,151								8

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the August 2022 Billing Cycle

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred - 59.448 Mills/kWh (See Sch. 7)	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 131 and 132	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	901,875	$ 24,310,041	$ 53,614,665	$ 29,304,624	$ 30,953,057	$ 11,141,464	$ 19,811,593	$ 9,493,031	1
2	Total Commercial	603,141	16,257,666	35,855,526	19,597,860	21,257,529	7,451,004	13,806,525	5,791,335	2
3	Total Industrial	788,890	21,264,529	46,897,933	25,633,404	24,153,888	9,745,685	14,408,203	11,225,201	3
4	Total Other	204,521	5,512,864	12,158,364	6,645,500	6,816,392	2,526,585	4,289,807	2,355,693	4
5	Total Retail kWh Sales Subject to Fuel Clause Adjustment	2,498,427	$ 67,345,100	$ 148,526,488	$ 81,181,388	$ 83,180,866	$ 30,864,738	$ 52,316,128	28,865,260	5
6	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	66,812								6
7	kWh Sales for Resale	330,870								7
8	Sales	2,896,109								8
9	Fuel Cost Variance from the June 2022 Billing Cycle (See Attachment A, Schedule 6, Page 1 of 3, Column H)								39,619,378	9
10	Fuel Cost Variance from the July 2022 Billing Cycle (See Attachment A, Schedule 6, Page 2 of 3, Column H)								19,491,417	10
11	Total Fuel Cost Variance for the Three (3) Months Ended August 2022								$ 87,976,055	11

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
June 2022

Line No.	Description	Total Actual June 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual June 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	734,023			734,023	1
2	Commercial	751,696			751,696	2
3	Industrial	728,793			728,793	3
4	Public Street and Highway Lighting	6,952			6,952	4
5	Other Public Authorities	197,014			197,014	5
6	Billed Retail Sales	2,418,478			2,418,478	6
7	Unbilled Retail Sales	30,057			30,057	7
8	Wholesale Sales	295,948	45,920	250,028	-	8
9	Total Native Load Sales (S)	2,744,483	45,920	250,028	2,448,535	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 154,931,063	$ 2,623,895	$ 13,919,351	$ 138,387,817	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	(16,906,711)	(282,879)	(1,540,236)	(15,083,596)	11
12	Wind and Solar REC Proceeds 5/	-	-	-	-	12
13	Prior Period Hedging Adjustment 6/	13,770	230	1,254	12,286	13
14	Prior Period Cost Adjustments 3/	(2,089,798)	1,595	(415,506)	(1,675,887)	14
15	Total Fuel Cost (F)	$ 135,948,324	$ 2,342,841	$ 11,964,863	$ 121,640,620	15
16	Fuel Cost - Mills per kWh (F/S)	49.535	51.020	47.854	49.679	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 (line 5) 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 and gas costs and steam revenues for the Purdue CHP plant.

2/ Hedging component subtotals follow: LMP hedging total ($12,436,137); Gas hedging total ($4,470,574).

3/ Prior Period Adjustment Totals by month: 1)Feb22 S105 Revised $3,592; 2)Mar22 S105 ($552,717); 3)Apr22 S105 ($498,768); 4)May22 S105 ($1,041,905).

Prior Period Adjustment WVPA 70 by month: 1)Mar22 S105 ($33,425); 2)Apr22 S105 $11,742; 3)May22 S105 $23,278.

Prior Period Adjustment Wholesale Formula Rate by month: 1)Feb22 S105 Revised $300; 2)Mar22 S105 ($303,720); 3)Apr22 S105 ($20,734); 4)May22 S105 ($91,352).

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)Mar22 S105 LMP $4,796; 2)Apr22 S105 LMP $4,778; 3)May22 S105 LMP $4,196.

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
July 2022

Line No.	Description	Total Actual July 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual July 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	872,818			872,818	1
2	Commercial	464,380			464,380	2
3	Industrial	620,991			620,991	3
4	Public Street and Highway Lighting	4,423			4,423	4
5	Other Public Authorities	150,704			150,704	5
6	Billed Retail Sales	2,113,316			2,113,316	6
7	Unbilled Retail Sales	349,378			349,378	7
8	Wholesale Sales	302,835	45,360	257,475	-	8
9	Total Native Load Sales (S)	2,765,529	45,360	257,475	2,462,694	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 158,879,404	$ 2,439,526	$ 13,594,993	$ 142,844,885	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	(3,658,687)	(60,010)	(340,629)	(3,258,048)	11
12	Wind and Solar REC Proceeds 5/	-	-	-	-	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	$ 155,220,717	$ 2,379,516	$ 13,254,364	$ 139,586,837	14
15	Fuel Cost - Mills per kWh (F/S)	56.127	52.458	51.478	56.681	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 (line 5) 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 and gas costs and steam revenues for the Purdue CHP plant.

2/ Hedging component subtotals follow: LMP hedging total $24,466; Gas hedging total ($3,683,153).

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 typ((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 custom

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
August 2022

Line No.	Description	Total Actual August 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual August 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	901,875			901,875	1
2	Commercial	603,141			603,141	2
3	Industrial	870,564			870,564	3
4	Public Street and Highway Lighting	5,907			5,907	4
5	Other Public Authorities	183,752			183,752	5
6	Billed Retail Sales	2,565,239			2,565,239	6
7	Unbilled Retail Sales	114,727			114,727	7
8	Wholesale Sales	330,870	51,870	279,000	-	8
9	Total Native Load Sales (S)	3,010,836	51,870	279,000	2,679,966	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 185,939,722	$ 3,245,365	$ 17,500,869	$ 165,193,488	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	(6,250,763)	(107,687)	(579,229)	(5,563,847)	11
12	Wind and Solar PPA REC Proceeds 5/	(349,992)	(6,030)	(32,432)	(311,530)	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	$ 179,338,967	$ 3,131,648	$ 16,889,208	$ 159,318,111	14
15	Fuel Cost - Mills per kWh (F/S)	59.565	60.375	60.535	59.448	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 (line 5) 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 and gas costs and steam revenues for the Purdue CHP plant.

2/ Hedging component subtotals follow: LMP hedging total ($58,999); Gas hedging total ($6,191,764).

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 (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 cus

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

ATTACHMENT A
SCHEDULE 8

Summary of Fuel Costs Incurred to Meet Native Load
Requirements by Week to Be Recovered Via the Fuel Adjustment Clause
for the Months of June, July and August 2022

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/			Line No.
		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)	
	June 2022																	
1	01 - 04	248,609.689	9,164,401.21	36.86	248,609.689	1,100,084.93	4.42	248,609.689	10,264,486.14	41.29	(2,762,737.73)	96,635.111	8,221,376.50	85.08	345,244.800	15,723,124.91	45.54	1
2	05 - 11	376,566.504	14,034,512.21	37.27	376,566.504	2,797,141.43	7.43	376,566.504	16,831,653.64	44.70	(2,976,390.05)	189,676.108	17,515,344.71	92.34	566,242.612	31,370,608.30	55.40	2
3	12 - 18	507,522.239	21,298,484.70	41.97	507,522.239	8,041,848.82	15.85	507,522.239	29,340,333.52	57.81	(12,098,164.27)	198,020.487	27,113,565.73	136.92	705,542.726	44,355,734.98	62.87	3
4	19 - 25	451,794.204	19,402,053.96	42.94	451,794.204	3,616,758.81	8.01	451,794.204	23,018,812.77	50.95	(4,761,085.39)	199,179.656	20,121,928.75	101.02	650,973.860	38,379,656.13	58.96	4
5	26 - 30	300,324.271	11,551,209.86	38.46	300,324.271	1,540,463.66	5.13	300,324.271	13,091,673.52	43.59	(1,464,424.24)	146,530.957	12,291,601.84	83.88	446,855.228	23,918,851.12	53.53	5
6	Subtotals	1,884,816.907	75,450,661.94	40.03	1,884,816.907	17,096,297.65	9.07	1,884,816.907	92,546,959.59	49.10	(24,062,801.68)	830,042.319	85,263,817.52	102.72	2,714,859.226	153,747,975.43	56.63	6
7													WVPA-IMPA Adjustment	6/	(321,912.432)	(17,033,520.64)	52.91	7
8													Native Alloc. Of Gas Pipeline Res. Fee	7/		310,359.55		8
9													Other Fuel Cost Adjustments			-		9
10															2,392,946.794	137,024,814.34	57.26	10

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/			Line No.
		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)	
	July 2022																	
11	01 - 02	116,821.538	4,840,774.70	41.44	116,821.538	465,004.67	3.98	116,821.538	5,305,779.37	45.42	(2,354,055.41)	77,534.442	6,892,659.23	88.90	194,355.980	9,844,383.19	50.65	11
12	03 - 09	508,279.248	19,954,044.02	39.26	508,279.248	4,763,976.67	9.37	508,279.248	24,718,020.69	48.63	(5,422,943.75)	169,434.220	17,058,034.48	100.68	677,713.468	36,353,111.42	53.64	12
13	10 - 16	506,821.494	19,305,096.84	38.09	506,821.494	1,892,987.11	3.74	506,821.494	21,198,083.95	41.83	(2,300,632.75)	166,292.178	14,407,552.41	86.64	673,113.672	33,305,003.61	49.48	13
14	17 - 23	530,216.958	21,037,183.26	39.68	530,216.958	573,827.13	1.08	530,216.958	21,611,010.39	40.76	(2,892,813.98)	172,909.994	18,649,658.05	107.86	703,126.952	37,367,854.46	53.15	14
15	24 - 30	452,706.665	16,610,926.97	36.69	452,706.665	994,381.71	2.20	452,706.665	17,605,308.68	38.89	(1,746,892.40)	210,555.276	21,172,573.39	100.56	663,261.941	37,030,989.67	55.83	15
16	31 - 31	49,182.640	1,699,354.65	34.55	49,182.640	200,837.00	4.08	49,182.640	1,900,191.65	38.64	(132,351.00)	37,461.114	3,156,025.83	84.25	86,643.754	4,923,866.48	56.83	16
17	Subtotals	2,164,028.543	83,447,380.44	38.56	2,164,028.543	8,891,014.29	4.11	2,164,028.543	92,338,394.73	42.67	(14,849,689.29)	834,187.224	81,336,503.38	97.50	2,998,215.767	158,825,208.82	52.97	17
18													WVPA-IMPA Adjustment	6/	(347,624.709)	(16,803,837.23)	48.34	18
19													Native Alloc. Of Gas Pipeline Res. Fee	7/		95,887.24	-	19
20													Other Fuel Cost Adustments			-		20
21															2,650,591.058	142,117,258.83	53.62	21

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/			Line No.
		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)	
	August 2022																	
22	01 - 06	380,390.454	17,386,504.60	45.71	380,390.454	1,562,358.28	4.11	380,390.454	18,948,862.88	49.81	(4,169,699.63)	218,772.831	24,447,789.50	111.75	599,163.285	39,226,952.75	65.47	22
23	07 - 13	423,183.833	17,769,524.83	41.99	423,183.833	1,440,936.24	3.40	423,183.833	19,210,461.07	45.40	(2,068,858.64)	235,703.420	24,244,574.20	102.86	658,887.253	41,386,176.63	62.81	23
24	14 - 20	393,542.628	14,756,054.54	37.50	393,542.628	1,850,406.19	4.70	393,542.628	16,606,460.73	42.20	(1,056,757.18)	247,378.872	23,617,737.93	95.47	640,921.500	39,167,441.48	61.11	24
25	21 - 27	440,846.551	17,740,357.30	40.24	440,846.551	1,278,606.79	2.90	440,846.551	19,018,964.09	43.14	(1,852,050.03)	213,034.944	21,927,708.78	102.93	653,881.495	39,094,622.84	59.79	25
26	28 - 31	218,146.697	9,735,605.29	44.63	218,146.697	969,068.21	4.44	218,146.697	10,704,673.50	49.07	(1,203,600.80)	167,004.657	18,705,977.41	112.01	385,151.354	28,207,050.11	73.24	26
27	Subtotals	1,856,110.163	77,388,046.56	41.69	1,856,110.163	7,101,375.71	3.83	1,856,110.163	84,489,422.27	45.52	(10,350,966.28)	1,081,894.724	112,943,787.81	104.39	2,938,004.887	187,082,243.81	63.68	27
28													WVPA-IMPA Adjustment	6/	(374,532.277)	(23,018,357.39)	61.46	28
29													Native Alloc. Of Gas Pipeline Res. Fee	7/		315,214.76	-	29
30															2,563,472.610	164,379,101.18	64.12	30

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).
Includes ($16,182.26), ($19,558.28) and ($21,881.87) respectively, for Excessive Energy Amounts for the months of June 2022, July 2022, August 2022.

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.

ATTACHMENT A
SCHEDULE 9

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
September 2021 through August 2022

Line No.	Description	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1	**MWh Sales (S)**	2,507,059	2,311,535	2,425,460	2,394,471	2,726,838	2,525,816	2,279,303	2,413,377	2,243,184	2,744,483	2,765,529	3,010,836	1
	Fuel Cost (F)													
2	Native Load Fuel Cost	$ 90,345,511	$ 100,744,893	$ 122,167,433	$ 94,800,355	$ 118,299,776	$ 91,823,499	$ 100,741,729	$ 118,693,849	$ 135,086,424	$ 154,931,063	$ 158,879,404	$ 185,939,722	2
3	Realized Hedging Activity	(1,692,759)	(6,425,721)	(7,433,658)	24,481,610	6,765,024	4,461,654	192,397	(3,992,487)	(12,636,327)	(16,906,711)	(3,658,687)	(6,250,763)	3
4	Other Adjustments	(47,377)	1,000	(352,500)	(357,235)	-	(765,521)	11,819	(13,581)	309	13,770	-	(349,992)	4
5	Prior Period Cost Adjustments 1/	53,758	-	-	3,176,810	-	-	(1,770,738)	-	-	(2,089,798)	-	-	5
6	Total Fuel Cost (F)	$ 88,659,133	$ 94,320,172	$ 114,381,275	$ 122,101,540	$ 125,064,800	$ 95,519,632	$ 99,175,207	$ 114,687,781	$ 122,450,406	$ 135,948,324	$ 155,220,717	$ 179,338,967	6
7	Fuel Cost Per kWh (Mills) F/S	$ 35.364	$ 40.804	$ 47.159	$ 50.993	$ 45.864	$ 37.817	$ 43.511	$ 47.522	$ 54.588	$ 49.535	$ 56.127	$ 59.565	7
	Fuel Cost Factor Restated Based On **Synchronization of Sumatra Adjustments**													
8	Remove: Prior Period Sumatra Adjustments Reflected in the Current Month	53,758	-	-	3,176,810	-	-	(1,770,738)	-	-	(2,089,798)	-	-	8
9	Remove: Hedging and Other Fuel Adjustments	(1,740,136)	(6,424,721)	(7,786,158)	24,124,375	6,765,024	3,696,133	204,216	(4,006,068)	(12,636,018)	(16,892,941)	(3,658,687)	(6,600,755)	9
10	Add: Subsequent Sumatra Adjustments that Pertain to the Month Presented	(962,802)	436,505	3,506,864	(312,175)	(685,384)	(769,587)	(552,717)	(498,768)	(1,041,905)	-	-	-	10
11	Restated Total Fuel Costs	$ 89,382,709	$ 101,181,398	$ 125,674,297	$ 94,488,180	$ 117,614,392	$ 91,053,912	$ 100,189,012	$ 118,195,081	$ 134,044,519	$ 154,931,063	$ 158,879,404	$ 185,939,722	11
12	Fuel Cost Factor	35.652	43.772	51.815	39.461	43.132	36.049	43.956	48.975	59.756	56.452	57.450	61.757	12
13	Percentage Variance from Preliminary Fuel Cost (Ln. 6) to Adjusted Fuel Cost, Excluding Hedging and Other Adjustments (Ln. 11)	0.82 %	7.27 %	9.87 %	(22.62 %)	(5.96 %)	(4.68 %)	1.02 %	3.06 %	9.47 %	13.96 %	2.36 %	3.68 %	13

1/ Prior period adjustments reflect the allocation of operating company fuel expense and purchase 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 June, July and August 2022

Line No.	Description	June 2022 Actual	June 2022 Forecast	July 2022 Actual	July 2022 Forecast	August 2022 Actual	August 2022 Forecast	Total Actual	Total Forecast	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	MWh Source:									
	Native Load Sales									
	Retail									
1	Residential	734,023	674,733	872,818	861,405	901,875	839,412	2,508,716	2,375,550	1
2	Commercial	751,696	569,935	464,380	603,697	603,141	588,495	1,819,217	1,762,127	2
3	Industrial	728,793	869,623	620,991	848,707	870,564	863,752	2,220,348	2,582,082	3
4	Public Street and Highway Lighting	6,952	4,132	4,423	4,118	5,907	4,107	17,282	12,357	4
5	Other Public Authorities	197,014	95,838	150,704	192,961	183,752	192,922	531,470	481,721	5
6	Total Billed Sales	2,418,478	2,214,261	2,113,316	2,510,888	2,565,239	2,488,688	7,097,033	7,213,837	6
7	Unbilled Retail Sales	30,057	174,326	349,378	9,272	114,727	78,082	494,162	261,680	7
8	Wholesale Sales	295,948	165,127	302,835	324,624	330,870	319,892	929,653	809,643	8
9	Total Native Load Sales (S)	2,744,483	2,553,714	2,765,529	2,844,784	3,010,836	2,886,662	8,520,848	8,285,160	9
	Fuel Cost:									
10	Native Load Fuel Cost	$ 154,931,063	$ 81,529,000	$ 158,879,404	$ 133,207,040	$ 185,939,722	$ 140,773,700	499,750,189	355,509,740	10
11	Hedging Activity and Other Adjustments	(16,892,941)	(636,523)	(3,658,687)	(4,577,073)	(6,600,755)	(3,666,564)	(27,152,383)	(8,880,160)	11
12	Total Fuel Cost	138,038,122	80,892,477	155,220,717	128,629,967	179,338,967	137,107,136	472,597,806	346,629,580	12
13	Fuel Cost - Mills Per kWh Before Prior Period Adjustment (F/S)	$ 50.297	$ 31.676	$ 56.127	$ 45.216	$ 59.565	$ 47.497	$ 55.464	$ 41.837	13
14	Percentage (%) Actual is Over (Under) Estimate Before Prior Period Adjustments	58.79 %		24.13 %		25.41 %		32.57 %		14
15	Prior Period Cost Adjustments	(2,089,798)	-	-	-	-	-	(2,089,798)	-	15
16	Total Fuel Cost (F_1)	$ 135,948,324	$ 80,892,477	$ 155,220,717	$ 128,629,967	$ 179,338,967	$ 137,107,136	$ 470,508,008	$ 346,629,580	16
17	Fuel Cost - Mills Per kWh After Prior Period Adjustment (F_1/S)	$ 49.535	$ 31.676	$ 56.127	$ 45.216	$ 59.565	$ 47.497	$ 55.218	$ 41.837	17
18	Percentage (%) Actual is Over (Under) Estimate After Prior Period Adjustments	56.38 %		24.13 %		25.41 %		31.98 %		18

ATTACHMENT A
SCHEDULE 11

DUKE ENERGY INDIANA, LLC

Other MISO Charges/(Credits) Allocated to Native Load Customers

Line No.	MISO Charge Description	cXL - MISO Charge Descripton	June-22	July-22	August-22	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	$ (10,581.06)	$ (3,972.53)	$ (105,950.67)	7
8	DA Virtual Energy Amount	DA Virtual	$ -	$ -	$ -	8
9	FTR Hourly Allocation Amount	FTR	$ (14,219,594.67)	$ (3,101,267.35)	$ (1,657,594.91)	9
10	FTR Monthly Allocation Amount	MISO FTR MTH ALLOC	$ (12,737.67)	$ (3,240.45)	$ (37,498.95)	10
11	FTR Transaction Amount	MISO FTR Transaction	$ -	$ -	$ -	11
12	FTR Yearly Allocation Amount	MISO FTR YRLY ALLOC	$ -	$ -	$ -	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	$ (3,431,637.51)	$ (4,045,226.94)	$ (4,063,429.00)	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	$ 23,127.27	$ 78,316.90	$ 55,969.15	20
21	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO RT RSG MKWHL	$ (1,163,859.44)	$ (531,013.62)	$ (876,821.70)	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	$ 12,737.83	$ 3,240.50	$ 37,434.94	25
26	RNU CRDFC Uplift Component	RNU CRDFC Uplift Component	$ (3,254.81)	$ (21,722.28)	$ (9.10)	26
27	FTR Full Funding Guarantee Amount	MISO FTR Full Fd Guar	$ -	$ -	$ -	27
28	FTR Guarantee Uplift Amount	MISO FTR Guar Uplift	$ -	$ -	$ -	28
29	Auction Revenue Rights Stage 2 Distribution Amount	MISO FTR ARR Stage 2	$ (171,870.82)	$ (169,500.36)	$ (171,755.71)	29
30	RT Price Volatility Make Whole Payment	MISO RT VOL MKWHL	$ (2,382,006.87)	$ (4,287,364.87)	$ (1,787,379.56)	30
31	DA Revenue Sufficiency Guarantee Distribution Amount	MISO DA RSG Dist Amt	$ 136,644.48	$ 125,922.76	$ 148,327.69	31
32	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	MISO RT RSG 1st Pass	$ 274,904.64	$ 273,552.36	$ 299,954.42	32
33	Net Regulation Adjustment Amount	MISO Net Reg Adj Amt	$ (1,753.44)	$ 129,367.68	$ 22,542.86	33
34	Regulation Cost Distribution Amount	MISO Reg Dist	$ 127,342.38	$ 118,114.51	$ 117,566.06	34
35	Spinning Reserve Cost Distribution Amount	MISO Spin Dist	$ 132,662.91	$ 52,032.68	$ 71,634.07	35
36	Supplemental Reserve Cost Distribution Amount	MISO Supp Dist	$ 33,737.83	$ 83,253.19	$ 31,269.08	36
37	RT Excessive/Deficient Energy Deployment Charge Amount	RT Excessive/Deficient Energy Deployment Charge Amount	$ 158,279.12	$ 199,480.72	$ 157,678.58	37
38	DA Regulation Amount	DA Regulation	$ (338,887.66)	$ (343,049.88)	$ (224,449.44)	38
39	DA Spinning Reserve Amount	DA Spinning	$ (208,849.11)	$ (86,145.23)	$ (60,630.07)	39
40	RT Regulation Amount	RT Regulation	$ (140,723.94)	$ (368,299.29)	$ (229,851.66)	40
41	RT Spinning Reserve Amount	RT Spinning	$ (24,360.15)	$ (267,671.33)	$ (135,521.47)	41
42	RT Supplemental Reserve Amount	RT Supplemental	$ (4,175.33)	$ (16,780.97)	$ (4,701.89)	42
43	DA Supplemental Reserve Amount	DA Supplemental	$ (3,478.06)	$ (3,827.99)	$ (20.67)	43
44	Auction Revenue Rights Infeasible Uplift Amount	MISO infesbl ARR UP	$ 55,739.46	$ 54,970.69	$ 55,702.12	44
45	Contingency Reserve Deployment Failure Charge Amount	Contingency Reserve Deployment Failure Charge Amount	$ -	$ -	$ -	45
46	FTR Monthly Transaction Amount	FTR Monthly Transaction Amount	$ (103,195.76)	$ -	$ -	46
47	FTR Annual Transaction Amount	FTR Annual Transaction Amount	$ 4,425,832.62	$ 4,364,790.90	$ 4,422,868.39	47
48	Auction Revenue Rights Transaction Amount	MISO ARR Revenues	$ (5,939,936.66)	$ (5,858,012.27)	$ (5,935,958.43)	48
49	MISO DR Alloc Uplift	MISO DR Alloc Uplift	$ 233,164.20	$ 169,761.55	$ 3,429.50	49
50	MISO Misc Round Adj	MISO Misc/Round Adj	$ (368,400.93)	$ (347,562.13)	$ 571,540.10	50
51	Internal Charge Type Related to MISO RT Regulation	MISO RT MIL MWP	$ (32,600.85)	$ (31,133.84)	$ (24,728.41)	51
52	Internal Charge Type Related to MISO RT Regulation	MISO Reg MIL UNDP	$ 88,850.55	$ 92,733.96	$ 71,939.60	52
53	MISO Disputed Amount	MISO Disputed Amount	$ -	$ -	$ -	53
54	RT Ramp Capability	RT Ramp Capability	$ (10,308.88)	$ (33,474.65)	$ (17,931.34)	54
55	DA Ramp Capability	DA Ramp Capability	$ (16,255.10)	$ (11,090.13)	$ (5,342.09)	55
56	Madison PJM Charges	Madison PJM Charges	$ (1,082,174.85)	$ (1,041,244.14)	$ (1,060,141.09)	56
57	Battery Charges	Native Battery MISO Charges	$ (135,284.56)	$ (43,770.18)	$ (25,406.45)	57
58	Short-Term Reserve Cost Distribution Amount	MISO ST Res Dist Amt	$ 54,665.97	$ 38,628.10	$ 21,452.84	58
59	Real-Time Short-Term Reserve Amount	MISO ST Reserve Amt	$ (2,939.93)	$ (9,122.30)	$ (9,775.35)	59
60	Day-Ahead Short-Term Reserve Amount	DA ST Reserve	$ (11,622.88)	$ (9,363.06)	$ (5,377.72)	60
61	Net Charges/(Credits) to Duke Energy Indiana (Attachment A, Schedule 8, column J, lines 6, 17 and 27)		$ (24,062,801.68)	$ (14,849,689.29)	$ (10,350,966.28)	61

ATTACHMENT B
SCHEDULE 1

DUKE ENERGY INDIANA, LLC

Determination of International Paper (formerly referred to as Temple-Inland, Inc.)
Fuel Cost Adjustment Factor Based on Estimated Average Fuel Costs
for the Months of January, February, and March 2023

Line No.	Description	Estimated Month of: January 2023 (A)	February 2023 (B)	March 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Source ATTACHMENT A	Line No.
	MWh Source:							
1	Steam Generation	2,136,699	1,954,027	1,726,210	5,816,936	1,938,979	Sch. 2, Line 7	1
2	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 8	2
3	Hydro and Solar Generation	41,802	38,194	42,761	122,757	40,919	Sch. 2, Line 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch. 2, Line 10	4
5	Gas Combustion Turbine	263,517	258,502	285,990	808,009	269,336	Sch. 2, Line 11	5
6	Integrated Gasification Combined Cycle	449,376	403,301	277,877	1,130,554	376,851	Sch. 2, Line 12	6
7	Purchased Power	29,093	27,970	300,180	357,243	119,081	Total, Sch 3, Col. A	7
8	Equivalent kWh - Steam Sale	15,387	14,296	14,226	43,909	14,637	Sch. 5, Line 2	8
	Less:							
9	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. A	9
10	Total kWh (K)	2,935,874	2,696,290	2,647,244	8,279,408	2,759,803		10
	Fuel Cost:							
11	Steam Generation	$ 67,292,000	$ 64,755,000	$ 60,479,000	$ 192,526,000	$ 64,175,334	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	18,682,000	17,361,000	16,185,000	52,228,000	17,409,333	Sch. 2, Line 4	15
16	Integrated Gasification Combined Cycle	20,205,000	19,237,000	13,599,000	53,041,000	17,680,333	Sch. 2, Line 5	16
17	Hedging Position	936,588	2,171,540	1,655,245	4,763,373	1,587,791	Sch. 1, Line 17	17
18	Purchased Power	1,916,000	1,836,000	22,354,000	26,106,000	8,702,000	Total, Sch 3, Col. C	18
19	Net MISO Energy Market	3,824,000	6,296,000	2,692,000	12,812,000	4,270,667	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)	$ 112,855,588	$ 111,656,540	$ 116,964,245	$ 341,476,373	$ 113,825,458		22
23	F / K (Mills Per kWh)					41.2440518		23
24	Equivalent Cost Per 1000 lbs Steam (Line 23 * 0.1084)					4.4708552		24
25	Less: Base Cost of Fuel Included in Rates Per 1000 lbs Steam					1.5890079		25
26	Fuel Cost Adjustment Factor Per 1000 lbs Steam					2.8818473		26

ATTACHMENT B
SCHEDULE 2

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Fuel Cost Incurred to Fuel Cost Billed
to International Paper (formerly Temple-Inland, Inc.)
For the Months of June through August 2022

Line No.	Month	Steam Supplied (lbs.)	Actual Fuel Cost Adjustment Factor 1/	Estimated Fuel Cost Adjustment Factor	Variance	Reconciliation Amount	Line No.
1	June 2022	106,107,426	3.5831686	1.7173391	1.8658295	197,978	1
2	July 2022	106,073,916	3.8663079	3.4255032	0.4408047	46,758	2
3	August 2022	102,715,502	4.8066939	3.4255032	1.3811907	141,870	3
4	TOTAL RECONCILIATION					$ 386,606	4

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

	June 2022	July 2022	August 2022
MWh Sales (K)	2,549,380	2,773,664	2,700,264
Fuel Cost (F)	$ 121,640,620	$ 139,586,837	$ 159,318,111
F/K (Mills Per kWh)	47.7138049	50.3257918	59.0009388
Equivalent Cost per 1000lbs Steam	5.1721765	5.4553158	6.3957018
Less: Base Cost of Fuel Included in Rates	1.5890079	1.5890079	1.5890079
Fuel Cost Charge Factor (Per 1000lbs Steam)	3.5831686	3.8663079	4.8066939