STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF DECEMBER 2026, JANUARY 2027, AND FEBRUARY 2027, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	**)**	**CAUSE NO. 38703 FAC 153**

VERIFIED APPLICATION

TO THE INDIANA UTILITY REGULATORY COMMISSION:

INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA (hereinafter called “Applicant” or “AES Indiana”) respectfully represents and shows this Commission:

1. Applicant is an electric generating utility and is a corporation organized and existing under the laws of the State of Indiana having its principal office at Indianapolis, Indiana. It is engaged in rendering electric public utility service in the State of Indiana and owns and operates, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other laws of the State of Indiana.

ELECTRIC SERVICE

2. With respect to electric service, this Application is filed pursuant to Ind. Code § 8-1-2-42 for the purpose of securing approval of a new fuel cost factor for electric service for the billing months of December 2026, January 2027, and February 2027 (the "Forecast Period").

3. AES Indiana is requesting recovery of projected fuel-related costs attributable to Applicant accepting transmission service from the Midcontinent Independent System Operator, Inc. ("MISO") for the Forecast Period. The Company's filing also reflects a true-up of fuel-related MISO costs and revenues for the period of May 2026, June 2026, and July 2026 (the "Historical Period"). As discussed further in the Company's testimony, the Company has included costs for contract for differences ("CfD") and credits for cash disbursements received from the joint venture renewable projects. The data and calculations supporting such estimated fuel cost and fuel cost factor are set forth in Schedules 1-7 attached hereto and made a part hereof.

4. Applicant represents that (i) Applicant has made every reasonable effort to acquire fuel and to generate and/or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible; (ii) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving Applicant's basic rates have not been offset by actual decreases in Applicant's other operating expenses; (iii) Applicant has performed the calculations required under Ind. Code § 8-1-2-42.3 and determined that no reduction in the fuel cost factor applied for is necessary because the sum of Applicant's differentials for the relevant period is less than zero; and (iv) the estimate of Applicant's prospective average fuel costs for the FAC period are reasonable after taking into consideration the reconciliation of Applicant's actual fuel cost recoveries for the reconciliation period.

5. In Cause No. 43414, Applicant and Indiana Office of Utility Consumer Counselor ("OUCC") agreed upon a "Benchmark" triggering mechanism for the judgment of the reasonableness of purchased power costs. Each day, a Benchmark is established based upon a generic Gas Turbine ("GT") with a generic GT heat rate of 12,500 btu/kWh, using the day ahead natural gas prices for the NYMEX Henry Hub, plus $0.60/mmbtu gas transport charge for a generic gas-fired GT. The Benchmark methodology was approved in Cause No. 43414 on April 23, 2008 ("Purchased Power Daily Benchmark(s)"). As explained by Applicant's witness Alexander Dickerson, Applicant continues to follow the guidelines and procedures established in Cause No. 43414. The Purchased Power Daily Benchmarks for the Historical Period are set forth in Attachment AD-1.

6. Applying the Purchased Power Daily Benchmarks set forth above to individual power purchase transactions included in this proceeding shows $14,846,893 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in the Historical Period, of which $944,362 is not recoverable. A summary of the purchased power volumes, costs, the total of hourly purchased power costs above the applicable Purchased Power Daily Benchmarks for the Historical Period and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment AD-2.

7. Consistent with the Commission's Order in Cause No. 43740, Applicant continues to apply ratemaking treatment to recover the purchased power costs incurred under the Lakefield Wind Park purchase power agreement.

8. The books and records of Applicant supporting the data and calculations set forth herein are available for inspection and review by the OUCC and this Commission. Applicant is

contemporaneously prefiling with the Commission its direct testimony, attachments, and workpapers in support of this Application.

9. Applicant's average cost of fuel for the Forecast Period, after taking into consideration its estimated and actual fuel costs for the Historical Period, is estimated to be $0.055352 for the proposed factor.

10. As more fully illustrated on Schedule 1, taking into account the projected fuel costs and fuel variance, the resulting fuel factor would be $0.015077. For rate mitigation purposes, AES Indiana proposes to spread the Historical Period variances over two FAC periods, resulting in a proposed fuel factor of $0.011541. This factor represents an increase from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of December 2026, January 2027, and February 2027.

11. A copy of the proposed Tariff is set forth in Attachment NHC-1-A, attached hereto and made a part hereof.

12. The names and addresses of Applicant's duly authorized representatives, to whom all correspondence and communications concerning this Application should be sent, are as follows:

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
Taft Stettinius & Hollister LLP
One Indiana Square, Suite 3500
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13. Applicant requests that the Commission approve a procedural schedule agreed to by the Applicant and the OUCC in lieu of conducting a prehearing conference. AES Indiana's proposed schedule is as follows:

Date	**Event**
October 22, 2026	OUCC/Intervenors File Case-in-Chief
October 29, 2026	Petitioner's Rebuttal Testimony
Week of November 9, 2026	Hearing
November 25, 2026	Order

14. Applicant seeks to make the fuel cost factor requested herein effective for all bills rendered for electric services beginning with the first billing cycle for December 2026 (Regular Billing District 41 and Special Billing District 01), which begins November 30, 2026. Such fuel cost factor, upon becoming effective, shall remain in effect for approximately three (3) months or until replaced by a different fuel cost factor.

WHEREFORE, Applicant respectfully requests that the Commission:

(i) approve this Application and the fuel cost factor requested herein as set forth in and supported by Schedules 1-7;

(ii) approve the proposed Tariff attached hereto as <u>Attachment NHC-1-A</u>;

(iii) approve AES Indiana's ongoing recovery of costs, gains, or losses, including any associated transactional costs, associated with the hedging plans through the fuel adjustment clause in accordance with the review of the reasonableness of the transaction(s) as described in Applicant's testimony; and

(iv) grant to Applicant all other appropriate relief.

INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

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Chad A. Rogers
Director, Regulatory Affairs

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Attorneys for Indianapolis Power & Light Company
d/b/a AES Indiana

Verification

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated this 17th day of September, 2026.

Natalie Herr Coklow

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Natalie Herr Coklow

Attachment NHC-1-A

STANDARD CONTRACT RIDER NO. 6
FUEL COST ADJUSTMENT
(Applicable to Rates RS, UW, CW, SS, MD, SH, OES, SL, PL, PH, HL, MU-1, APL, and EVX)

In addition to the rates and charges set forth in the above mentioned Rates, a fuel cost adjustment applicable for approximately three (3) months or until superseded by a subsequent factor shall be made in accordance with the following provisions:

A. The fuel cost adjustment shall be calculated by multiplying the KWH billed by an Adjustment Factor per KWH established according to the following formula:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.043811$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of ~~September~~ December 2026 and consisting of the following costs:

   (a) The average cost of fossil and nuclear fuel consumed in the Company's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants including, as to fossil fuel, only those items listed in Account 151 and as to nuclear fuel only those items listed in Account 518 (except any expense for fossil fuel included in Account 151) of the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees;

   (b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below;

   (c) The net energy cost, exclusive of capacity or demand charges, of energy purchased on an economic dispatch basis, and energy purchased as a result of a scheduled outage, when the costs thereof are less than the Company's fuel cost of replacement net generation from its own system at that time; less

   (d) The cost of fossil and nuclear fuel recovered through intersystem sales including fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:

   (a) Net Generation,
   (b) Purchases and
   (c) Interchange-in, less
   (d) Inter-system Sales,
   (e) Energy Losses and Company Use.

STANDARD CONTRACT RIDER NO. 6 (Continued)

B. The Adjustment Factor as computed above shall be further modified to allow the recovery of revenue-based tax charges occasioned by the fuel adjustment revenues.

C. The Adjustment Factor may be further modified to reflect the difference between incremental fuel cost actually experienced during the months of ~~February~~ May 2026 through ~~April~~ July 2026.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~September~~ December 2026 will be $~~0.005211~~0.011541 per KWH.

STANDARD CONTRACT RIDER NO. 6
FUEL COST ADJUSTMENT
(Applicable to Rates RS, UW, CW, SS, MD, SH, OES, SL, PL, PH, HL, MU-1, APL, and EVX)

In addition to the rates and charges set forth in the above mentioned Rates, a fuel cost adjustment applicable for approximately three (3) months or until superseded by a subsequent factor shall be made in accordance with the following provisions:

A. The fuel cost adjustment shall be calculated by multiplying the KWH billed by an Adjustment Factor per KWH established according to the following formula:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.043811$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of December 2026 and consisting of the following costs:

   (a) The average cost of fossil and nuclear fuel consumed in the Company's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants including, as to fossil fuel, only those items listed in Account 151 and as to nuclear fuel only those items listed in Account 518 (except any expense for fossil fuel included in Account 151) of the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees;

   (b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below;

   (c) The net energy cost, exclusive of capacity or demand charges, of energy purchased on an economic dispatch basis, and energy purchased as a result of a scheduled outage, when the costs thereof are less than the Company's fuel cost of replacement net generation from its own system at that time; less

   (d) The cost of fossil and nuclear fuel recovered through intersystem sales including fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:

   (a) Net Generation,
   (b) Purchases and
   (c) Interchange-in, less
   (d) Inter-system Sales,
   (e) Energy Losses and Company Use.

STANDARD CONTRACT RIDER NO. 6 (Continued)

B. The Adjustment Factor as computed above shall be further modified to allow the recovery of revenue-based tax charges occasioned by the fuel adjustment revenues.

C. The Adjustment Factor may be further modified to reflect the difference between incremental fuel cost actually experienced during the months of May 2026 through July 2026.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for December 2026 will be $0.011541 per KWH.

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with December 2026 Based on the Estimated
Three Months Average of December 2026, January and February 2027

Line No.	Description	(A) December	(B) January	(C) February	(D) Total	(E) Estimated Three Month Average	Line No.
		Estimated Month of:					
	kWh Source (000's)						
1	Coal and Oil Generation	-	-	-	-	-	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	1,553,197	1,790,068	1,441,306	4,784,572	1,594,857	5
6	Wind Generation	24,341	21,771	23,260	69,372	23,124	6
	Purchases through MISO:						
7	Wind and MISO Spot Purchases (1)	40,319	41,361	47,536	129,216	43,072	7
8	Other	-	-	-	-	-	8
9	Rate REP Solar	5,909	5,469	6,223	17,601	5,867	9
	LESS:						
10	Energy Losses and Company Use	55,693	60,198	53,332	169,222	56,407	10
11	Inter-System Sales through MISO	380,966	515,348	328,225	1,224,539	408,180	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,187,108	1,283,124	1,136,768	3,607,000	1,202,333	14
	Fuel Cost ($)						
15	Coal and Oil Generation	-	-	-	-	-	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	64,533,175	81,062,544	64,921,761	210,517,480	70,172,493	19
	Purchases through MISO:						
20	Wind and MISO Spot Purchases (1)	4,853,132	4,627,864	5,006,353	14,487,348	4,829,116	20
21	Other	-	-	-	-	-	21
22	Rate REP Solar	974,250	911,100	1,039,840	2,925,190	975,063	22
23	MISO Components of Cost of Fuel	2,179,529	2,355,815	2,087,109	6,622,453	2,207,484	23
	Less:						
24	Inter-System Sales through MISO	12,761,049	20,974,974	11,989,067	45,725,091	15,241,697	24
25	Inter-System Sales other than MISO	-	-	-	-	-	25
26	Non-Jurisdictional Retail Sales	-	-	-	-	-	26
27	Transmission Losses	572,602	752,024	597,928	1,922,554	640,851	27
28	Lakefield PPA Adjustment	-	-	-	-	-	28
29	**Total Fuel Cost (F)**	$ 59,206,434	$ 67,230,325	$ 60,468,068	$ 186,904,827	$ 62,301,608	29
30	**F ÷ S (Line 29 ÷ Line 14) (Mills/kWh)**					51.817	30
		Months to be Reconciled					
		May	June	July	Total	50%	
31	Fuel Cost Variance (includes Joint Venture CfD and Cash Receipts)	$ 1,831,086	$ 7,905,897	$ 15,767,268	$ 25,504,252	$ 12,752,126	31
32	Total Fuel Cost Variance and Adjustments Included in this Filing					12,752,126	32
	(Mills/kWh)						
33	Variance Charge (Line 32 Total divided by estimated Indiana jurisdictional sales of		3,607,000	kWh (000's)		3.535	33
34	Adjusted Fuel Cost Charge (Line 30 + Line 33)					55.352	34
35	Less: Base Cost of Fuel Included in Rates					43.811	35
36	Fuel Cost Charge					11.541	36

(1) Includes Lakefield Wind and MISO Purchased Power.

AES INDIANA
Determination of Net Energy Cost of Purchased Power
For the Estimated Months of December 2026, January and February 2027

Line No	Supplier	kWh Purchased (000's)	Energy *	Line No
		(A)	(B)	
	December			
	Purchases through MISO:			
1	Wind and MISO Spot Purchases (1)	40,319	$ 4,853,132	1
2	Other	-	-	2
3	Rate REP Solar	5,909	974,250	3
4	MISO Components of Cost of Fuel	-	2,179,529	4
5	Total	46,229	8,006,911	5
	January			
	Purchases through MISO:			
6	Wind and MISO Spot Purchases (1)	41,361	$ 4,627,864	6
7	Other	-	-	7
8	Rate REP Solar	5,469	911,100	8
9	MISO Components of Cost of Fuel	-	2,355,815	9
10	Total	46,830	$ 7,894,779	10
	February			
	Purchases through MISO:			
11	Wind and MISO Spot Purchases (1)	47,536	$ 5,006,353	11
12	Other	-	-	12
13	Rate REP Solar	6,223	1,039,840	13
14	MISO Components of Cost of Fuel	-	2,087,109	14
15	Total	53,759	$ 8,133,302	15
16	Total Net Energy Cost of Purchased Power	146,817	$ 24,034,991	16

* Demand Charges have not been estimated.

(1) Includes Lakefield Wind and MISO Purchased Power.

AES INDIANA
Determination of Fuel Costs Recovered Through
Inter-System and Non-Jurisdictional Retail Sales by Month
For the Estimated Months of December 2026, January and February 2027

Line No.	Purchaser	kWh Sold (000's)	Fuel Cost *	Line No.
		(A)	(B)	
	December			
1	Inter-System Sales through MISO	380,966	$ 12,761,049	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	380,966	$ 12,761,049	4
	January			
5	Inter-System Sales through MISO	515,348	$ 20,974,974	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	515,348	$ 20,974,974	8
	February			
9	Inter-System Sales through MISO	328,225	$ 11,989,067	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	328,225	$ 11,989,067	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	1,224,539	$ 45,725,091	13

* Demand Charges have not been estimated.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for May 2026

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 38.892 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed (E)	Fuel Cost [(1)] Variance From Cause No. 38703-FAC150 (F)	Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (G) (Col E - Col F)	Fuel Cost Variance (H) (Col D - Col G)	Line No.
1	Total Residential	278,902	$ 10,884,708	$ 10,847,055	$ (37,653)	$ (1,546,549)				1
2	Total Commercial	113,607	4,433,740	4,418,403	(15,337)	(629,397)				2
3	Total Industrial	488,086	19,048,532	18,982,641	(65,891)	(2,730,092)				3
4	Total Electric Vehicle Public Charging Stations	4	156	156	-	(20)				4
5	Total Lighting	36	1,405	1,400	(5)	(205)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	880,635	$ 34,368,541	$ 34,249,655	$ (118,886)	$ (4,906,263)	$ (6,376,383)	$ 1,470,120	$ (1,589,006)	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Total Sales	880,635								10
11	Hardy Hills Contract for Differences (CfD)								1,162,019	11
12	Hardy Hills Cash Receipts								(549,500)	12
13	Pike BESS Contract for Differences (CfD)								2,706,000	13
14	Pike BESS Cash Receipts, including MISO transmission revenue								(560,000)	14
15	Pete Energy Center Contract for Differences (CfD)								1,581,573	15
16	Pete Energy Center Cash Receipts								(920,000)	16
17	Fuel Cost Variance with CfD and Receipts								$ 1,831,086	17

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 150 $(19,129,148) or $(6,376,382.69) per month.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for June 2026

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 44.370 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed (E)	Fuel Cost (1) Variance From Cause No. 38703-FAC151 (F)	Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (G) (Col E - Col F)	Fuel Cost Variance (H) (Col D - Col G)	Line No.
1	Total Residential	366,559	$ 14,305,698	$ 16,264,224	$ 1,958,526	$ 1,459,287				1
2	Total Commercial	134,339	5,242,848	5,960,621	717,773	532,707				2
3	Total Industrial	513,437	20,037,906	22,781,200	2,743,294	1,929,687				3
4	Total Electric Vehicle Public Charging Stations	4	156	177	21	14				4
5	Total Lighting	8,853	345,506	392,808	47,302	(8,322)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,023,192	$ 39,932,114	$ 45,399,030	$ 5,466,916	$ 3,913,373	$ 3,579,838	$ 333,535	$ 5,133,381	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Total Sales	1,023,192								10
11	Hardy Hills Contract for Differences (CfD)								751,226	11
12	Hardy Hills Cash Receipts								(1,330,000)	12
13	Pike BESS Contract for Differences (CfD)								2,706,000	13
14	Pike BESS Cash Receipts, including MISO transmission revenue								(425,000)	14
15	Pete Energy Center Contract for Differences (CfD)								2,110,289	15
16	Pete Energy Center Cash Receipts								(1,040,000)	16
17	Fuel Cost Variance with CfD and Receipts								$ 7,905,897	17

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 151 $21,479,027 spread over two FAC periods or $(3,579,838) per month.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for July 2026

Billed Rates Approved in Cause No. 45911

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 51.627 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Line No.
1	Total Residential	505,215	$ 19,717,021	$ 26,082,735	$ 6,365,714	1
2	Total Commercial	162,607	6,346,063	8,394,912	2,048,849	2
3	Total Industrial	608,166	23,734,894	31,397,786	7,662,892	3
4	Total Electric Vehicle Public Charging Stations	2	78	103	25	4
5	Total Lighting	4,219	164,655	217,814	53,159	5
6	Total Other					6
7	Total Retail Sales Subject to FAC	1,280,209	$ 49,962,711	$ 66,093,350	$ 16,130,639	7

Billed Rates Approved in Cause No. 46258

Line No.	Class of Customers	kWh Sales (In 000's) (E)	Base Cost of Fuel Included in Rates 43.811 Mills/kWh (F) (Col E * mills above)	Actual Cost of Fuel Incurred 51.627 Mills/kWh (G) (Col E * mills above)	Actual Incremental Cost of Fuel Incurred (H) (Col G - Col H)	Actual Incremental Cost of Fuel Incurred Total (I)	Actual Incremental Cost of Fuel Billed (J)	Fuel Cost [(1)] Variance From Cause No. 38703-FAC151 (K)	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (L) (Col J - Col K)	Fuel Cost Variance (M) (Col I - Col L)	Line No.
8	Total Residential	11,631	$ 509,562	$ 600,474	$ 90,912	$ 6,456,626	$2,014,489				8
9	Total Commercial	3,744	164,028	193,291	29,263	$ 2,078,112	649,705				9
10	Total Industrial	14,001	613,398	722,830	109,432	$ 7,772,324	2,298,646				10
11	Total Electric Vehicle Public Charging Stations	-	-	-	-	$ 25	10				11
12	Total Lighting	97	4,250	5,008	758	$ 53,917	13,773				12
13	Total Other										13
14	Total Retail Sales Subject to FAC	29,473	$ 1,291,238	$ 1,521,603	$ 230,365	$ 16,361,004	$4,976,623	$ 3,579,838	$ 1,396,785	$ 14,964,219	14
15	Total Retail Sales NOT Subject to FAC	-									15
16	Total Non-jurisdictional Retail Sales	-									16
17	Total Sales	1,309,682									17
18	Hardy Hills Contract for Differences (CfD)									(44,199)	18
19	Hardy Hills Cash Receipts									(1,330,000)	19
20	Pike BESS Contract for Differences (CfD)									2,706,000	20
21	Pike BESS Cash Receipts, including MISO transmission revenue									(425,000)	21
22	PEC CFD									1,336,249	22
23	Pete Energy Center Cash Receipts									(1,440,000)	23
24	Fuel Cost Variance with CFD and Distributions									$ 15,767,268	24

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 151 $21,479,027 spread over two FAC periods or $(3,579,838) per month.

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation May 2026

Line No.	Description	May Actual	May Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	255,981	195,387	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	5	-	4
5	Gas Generation	657,813	738,602	5
6	Wind Generation	20,051	18,884	6
	Purchases through MISO:			
7	Wind and MISO Spot Purchases	129,428	158,564	7
8	Other	1,552	-	8
9	Rate REP Solar	12,162	13,904	9
	LESS:			
10	Energy Losses and Company Use	52,439	47,174	10
11	Inter-System Sales through MISO	96,079	72,641	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	928,474	1,005,525	14
	Fuel Cost			
15	Coal and Oil Generation	$ 7,448,387	$ 5,651,773	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	4,316	-	18
19	Gas Generation	21,587,551	27,110,210	19
20	Financial Hedges (Gains)/Losses & Transactional Fees	-	-	20
	Purchases through MISO:			
21	Wind and MISO Spot Purchases	7,175,127	7,777,799	21
22	Other	56,825	-	22
23	MISO Components of Cost of Fuel	623,064	1,190,542	23
24	Rate REP Solar	1,976,370	2,368,320	24
	LESS:			
25	Inter-System Sales through MISO	2,546,563	1,971,462	25
26	Inter-System Sales other than MISO	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	27
28	Transmission Losses	174,482	392,970	28
29	Lakefield PPA Adjustment	-	-	29
30	Purchased Power in Excess	40,440	-	30
31	Total Fuel Costs (F)	$ 36,110,155	$ 41,734,211	31
32	F / S (Mills/kWh)	38.892	41.505	32
	Weighted Average Deviation	6.72%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation June 2026

Line No.	Description	June Actual	June Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	224,153	236,890	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	-	-	4
5	Gas Generation	892,889	1,153,245	5
6	Wind Generation	14,246	13,711	6
	Purchases through MISO			
7	Wind and MISO Spot Purchases	103,218	47,592	7
8	Other	1,031	-	8
9	Rate REP Solar	12,326	15,341	9
	LESS:			
10	Energy Losses and Company Use	61,556	54,524	10
11	Inter-System Sales through MISO	95,084	250,068	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,091,223	1,162,188	14
	Fuel Cost			
15	Coal and Oil Generation	$ 11,610,038	$ 6,377,335	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	2,066	-	18
19	Gas Generation	27,931,772	34,632,180	19
20	Financial Hedges (Gains)/Losses & Transactional Fees	8,817	-	20
	Purchases through MISO			
21	Wind and MISO Spot Purchases	8,355,432	3,683,753	21
22	Other	39,845	-	22
23	MISO Components of Cost of Fuel	1,045,615	1,055,267	23
24	Rate REP Solar	1,959,769	2,723,530	24
	LESS:			
25	Inter-System Sales through MISO	2,137,141	6,022,103	25
26	Inter-System Sales other than MISO	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	27
28	Transmission Losses	281,889	403,023	28
29	Lakefield PPA Adjustment	-	-	29
30	Purchased Power in Excess	116,762	-	30
31	Total Fuel Costs (F)	$ 48,417,562	$ 42,046,938	31
32	F / S (Mills/kWh)	44.370	36.179	32
	Weighted Average Deviation	-18.46%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation July 2026

Line No.	Description	July Actual	July Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	-	-	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	10	-	4
5	Gas Generation	1,254,083	1,318,032	5
6	Wind Generation	8,061	8,815	
	Purchases through MISO			
7	Wind and MISO Spot Purchases	160,002	78,531	7
8	Other	887	-	8
9	Rate REP Solar	13,161	14,195	9
	LESS:			
10	Energy Losses and Company Use	72,622	60,318	10
11	Inter-System Sales through MISO	67,080	73,577	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,296,502	1,285,679	14
	Fuel Cost			
15	Coal and Oil Generation	$ 52,200	$ -	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	2,468	-	18
19	Gas Generation	45,550,782	45,065,079	19
20	Financial Hedges (Gains)/Losses & Transactional Fees	355,887	-	20
	Purchases through MISO			
21	Wind and MISO Spot Purchases	19,513,381	8,361,345	21
22	Other	34,610	-	22
23	MISO Components of Cost of Fuel	2,205,438	1,167,397	23
24	Rate REP Solar	2,116,503	2,458,110	24
	LESS:			
25	Inter-System Sales through MISO	1,893,515	2,013,898	25
26	Inter-System Sales other than MISO	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	27
28	Transmission Losses	$216,369	506,749	28
29	Lakefield PPA Adjustment	-	-	29
30	Purchased Power in Excess	787,159	-	30
31	Total Fuel Costs (F)	$ 66,934,226	$ 54,531,283	31
32	F / S (Mills/kWh)	51.627	42.414	32
	Weighted Average Deviation	-17.85%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
May, June, and July 2026

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	480,134	432,277	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	15	-	4
5	Gas Generation	2,804,785	3,209,879	5
6	Wind Generation	42,358	41,410	
	Purchases through MISO			
7	Wind and MISO Spot Purchases	392,648	284,687	7
8	Other	3,470	-	8
9	Rate REP Solar	37,649	43,440	9
	LESS:			
10	Energy Losses and Company Use	186,617	162,016	10
11	Inter-System Sales through MISO	258,243	396,286	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	3,316,199	3,453,392	14
	Fuel Cost			
15	Coal and Oil Generation	$ 19,110,625	$ 12,029,108	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	8,850	-	18
19	Gas Generation	95,070,105	106,807,469	19
20	Financial Hedges Gains/Losses & Transactional Fees	364,704	-	20
	Purchases through MISO			
21	Wind and MISO Spot Purchases	35,043,940	19,822,896	21
22	Other	131,280	-	22
23	MISO Components of Cost of Fuel	3,874,117	3,413,205	23
24	Rate REP Solar	6,052,642	7,549,960	24
	LESS:			
25	Inter-System Sales through MISO	6,577,219	10,007,464	25
26	Inter-System Sales other than MISO	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	27
28	Transmission Losses	672,740	1,302,742	28
29	Lakefield PPA Adjustment	-	-	29
30	Purchased Power in Excess	944,361	-	30
31	Total Fuel Costs (F)	$ 151,461,943	$ 138,312,432	31
32	F / S (Mills/kWh)	45.673	40.051	32
	Weighted Average Deviation	-12.31%		

AES INDIANA
Determination of MISO Components of Fuel Cost
May, June, and July 2026

Line No.	Energy Market FAC Adjustment Components	Total May (A)	Total June (B)	Total July (C)	Line No.
1	Delta LMP[1]	$ 1,268,635	$ 2,966,969	$ 6,276,938	1
2	FTR (Revenue) / Expenses	(766,915)	(1,700,825)	(4,094,711)	2
3	RT Marg. Loss Surplus Credit	(118,773)	(413,262)	(766,624)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	(4,846)	(21,364)	(8,990)	5
5a	RSG 1st Pass Charges	11,377	8,083	60,481	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	(8,943)	(66,964)	65,592	6
7	Ancillary Services Revenue	4,476	(99,340)	(133,181)	7
8	Ancillary Services Costs	212,773	363,991	785,786	8
9	Ancillary Services Incentive to Follow Dispatch[2]	15,977	8,220	18,679	9
10	Ramp Capability[3]	9,303	109	1,468	10
11	Total (Columns A, B, & C to Schedule 5, line 25)	$ 623,064	$ 1,045,615	$ 2,205,438	11

Negative amount is a credit to expense (**payment from MISO**)
Positive amount is a debit to expense (**payment to MISO**)

[1]Differential of MCC and MLC between the load zone and generation pricing nodes
[2]Net of Contingency Reserve Deployment Failure Credit
[3]Ramp Capability Payments Net of Uplift

AES INDIANA
MISO Charges by Month by Charge Type

Line No.	Charge Type	May-26 Invoice Total	Jun-26 Invoice Total	Jul-26 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$ 165,909	$ 194,556	$ 202,836	1
2	Day Ahead Regulation Amount	-	-	-	2
3	Day Ahead Spinning Reserve Amount	(2,050)	(844)	-	3
4	Day-Ahead Short-Term Reserve Amount	(39,760)	(110,553)	(144,679)	4
5	Day Ahead Supplemental Reserve Amount	-	-	-	5
6	Day Ahead Asset Energy Amount	(55,464)	539,364	21,519,781	6
7	Day Ahead Financial Bilateral Transaction Congestion Amount	-	-	-	7
8	Day Ahead Financial Bilateral Transaction Loss Amount	-	-	-	8
9	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	9
10	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	10
11	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	-	-	11
12	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	-	-	-	12
13	Day Ahead Non-Asset Energy Amount	-	-	-	13
14	Day Ahead Ramp Capability Amount	(6,513)	(10,224)	(11,854)	14
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	31,308	31,194	32,322	15
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	(35,661)	(50,686)	(36,632)	16
17	Day Ahead Schedule 24 Allocation Amount	33,493	33,101	34,427	17
18	Day Ahead Virtual Energy Amount	-	-	-	18
	Day Ahead Subtotal	$ 91,262	$ 625,908	$ 21,596,201	
19	Financial Transmission Rights Market Administration Amount	$ 1,247	$ 2,649	$ 3,357	19
20	Auction Revenue Rights Transaction Amount	(746,862)	(1,459,460)	(1,459,460)	20
21	Financial Transmission Rights Annual Transaction Amount	275,737	652,457	652,457	21
22	Auction Revenue Rights Infeasible Uplift Amount	30,076	3,537	3,537	22
23	Auction Revenue Rights Stage 2 Distribution Amount	(174,555)	(401,094)	(400,751)	23
24	Financial Transmission Rights Full Funding Guarantee Amount	(6,609)	1	-	24
25	Financial Transmission Guarantee Uplift Amount	8,148	(1)	-	25
26	Financial Transmission Rights Hourly Allocation Amount	(147,560)	(484,807)	(2,830,446)	26
27	Financial Transmission Rights Monthly Allocation Amount	(5,290)	(11,457)	(60,047)	27
28	Financial Transmission Rights Monthly Transaction Amount	-	-	-	28
29	Financial Transmission Rights Transaction Amount	-	-	-	29
30	Financial Transmission Rights Yearly Allocation Amount	-	-	-	30
	Financial Transmission Rights Subtotal	$ (765,668)	$ (1,698,175)	$ (4,091,353)	
31	Real Time Market Administration Amount	$ 19,196	$ 20,510	$ 22,721	31
32	Contingency Reserve Deployment Failure Charge Amount	-	-	-	32
33	Excessive Energy Amount	(7,409)	(5,075)	(3,444)	33
34	Real Time Excessive Deficient Energy Deployment Charge Amount	16,031	8,266	20,875	34
35	Net Regulation Adjustment Amount	-	-	-	35
36	Non-Excessive Energy Amount	790,630	2,272,966	(107,878)	36
37	Real Time Regulation Amount	-	-	-	37
38	Regulation Cost Distribution Amount	101,803	107,066	56,762	38
39	Real Time Spinning Reserve Amount	(898)	(1,792)	(415)	39
40	Spinning Reserve Cost Distribution Amount	32,306	28,495	25,204	40
41	Real Time Short-Term Reserve Amount	47,184	13,849	11,918	41
42	Real-Time Short-Term Reserve Deployment Failure Charge Amount	-	-	-	42
43	Short-Term Reserve Cost Distribution Amount	74,394	3,777	692,397	43
44	Real Time Supplemental Reserve Amount	-	-	(4)	44
45	Supplemental Reserve Cost Distribution Amount	4,270	224,652	11,424	45
46	Real Time Asset Energy Amount	324,620	949,366	12,082	46
47	Real Time Demand Response Allocation Uplift Charge	664	31	118	47
48	Real Time Financial Bilateral Transaction Congestion Amount	-	-	-	48
49	Real Time Financial Bilateral Transaction Loss Amount	-	-	-	49
50	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	50
51	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	51
52	Real Time Distribution of Losses Amount	(118,773)	(413,262)	(766,624)	52
53	Real Time Miscellaneous Amount	17	(121,069)	(56)	53
54	Real Time MVP Distribution Amount	(29,761)	(12,709)	(12,921)	54
55	Real Time Non-Asset Energy Amount	-	-	-	55
56	Real Time Net Inadvertent Distribution Amount	(8,943)	(66,964)	65,592	56
57	Real Time Price Volatility Make Whole Payment	(106,820)	(99,557)	(99,557)	57
58	Real Time Resource Adequacy Auction Amount	217,494	(1,130,561)	(1,443,729)	58
59	Real Time Ramp Capability Amount	2,233	(3,192)	590	59
60	Real Time Revenue Neutrality Uplift Amount	433,600	587,144	590,986	60
61	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	14,448	8,791	114,121	61
62	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	(1,553)	(5,756)	(4,853)	62
63	Real-Time Storage as Transmission Only Asset Amount	-	-	-	63
64	Real Time Schedule 24 Allocation Amount	3,874	3,486	3,845	64
65	Real Time Schedule 24 Distribution Amount	(1,862)	(2,449)	(2,514)	65
66	Real Time Schedule 49 Cost Distribution Amount	60,002	58,273	57,547	66
67	Real Time Virtual Energy Amount	-	-	-	67
	Real Time Subtotal	$ 1,866,747	$ 2,424,286	$ (755,813)	
	Grand Total	$ 1,192,341	$ 1,352,019	$ 16,749,035	

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the forgoing was served by electronic transmission on the Office of Utility Consumer Counselor, 115 W. Washington Street, Suite 1520 South, Indianapolis, Indiana 46204, (infomgt@oucc.in.gov) and a copy was served by electronic transmission to Gregory T. Guerrettaz, Financial Solutions Group, Inc., 2680 East Main Street, Suite 223, Plainfield, Indiana 46168 (greg@fsgcorp.com).

In addition, a courtesy copy was provided by electronic transmission to Anne Becker, Lewis & Kappes, One American Square, Suite 2500, Indianapolis, Indiana 46282, (abecker@lewis-kappes.com), and a courtesy copy to: ATyler@lewis-kappes.com and ETennant@Lewis-kappes.com.

Dated this 17th day of September, 2026.

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