FILED
June 16, 2025
INDIANA UTILITY
REGULATORY COMMISSION

OFFICIAL
EXHIBITS

**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 SEPTEMBER 2025 THROUGH NOVEMBER 2025, 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 148** |

IURC
PETITIONER'S
EXHIBIT NO. 1
8-11-25
DATE
AT
REPORTER

**SUBMISSION OF DIRECT TESTIMONY OF NATALIE HERR COKLOW**

Applicant Indianapolis Power & Light Company d/b/a AES Indiana ("Applicant" or "AES Indiana"), by counsel, hereby submits the direct testimony and attachments of Natalie Herr Coklow.

Respectfully submitted,

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

## CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 16th day of June, 2025, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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

VERIFIED TESTIMONY OF NATALIE HERR COKLOW
MANAGER IN REGULATORY ACCOUNTING

**Q1. Please state your name, employer, and business address.**

A1. My name is Natalie Herr Coklow. I am employed by AES US Services, LLC ("the Service Company"), which is the Service Company that serves Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or the "Applicant"). The Service Company is located at One Monument Circle, Indianapolis, Indiana 46204. The Service Company provides accounting, legal, human resources, information technology and other corporate services to the businesses owned by The AES Corporation in the United States of America, including AES Indiana.

**Q2. What is your position with the Service Company?**

A2. I am a Director in the Regulatory Accounting department.

**Q3. Please summarize your work experience with the Service Company.**

A3. I began employment with the Service Company in July 2013. During my tenure with the Service Company, I have worked in Regulatory Accounting on various AES Indiana and Dayton Power & Light Company d/b/a AES Ohio ("AES Ohio" or "DP&L") regulatory filings and the associated accounting entries for both companies. I am responsible for the various general ledger entries, the reconciliation of regulatory asset and liability accounts, the computation and tracking of various costs for regulatory filings, and the preparation of supporting schedules for these filings. These regulatory filings for AES Indiana have included filings related to the Fuel Adjustment Clause ("FAC") (Cause No. 38703-FAC XX), AES Indiana's recent basic rate cases (Cause Nos. 45029 and 45911), the

Environmental Compliance Cost Recovery Adjustment ("ECCRA") (Cause No. 42170-ECR XX), and the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") (Cause No 45264-TDSIC XX).

**Q4. Please summarize your prior work experience.**

A4. Prior to the Service Company, I was employed by London Witte Group, LLC ("LWG") for seven years. LWG is a certified public accounting firm that provides an array of accounting and consulting services to public utility, private and governmental clients. At LWG, I worked on the review of Gas Cost Adjustments filed with this Commission by various Indiana utilities, performed financial statement audits for predominately gas and electric utility clients, completed rate design for municipally owned utilities, and completed or reviewed financial statements and tax returns.

**Q5. Please summarize your educational qualifications.**

A5. I hold a Bachelor of Science Degree in Accounting from Indiana University.

**Q6. Have you previously testified before this Commission?**

A6. Yes. I have submitted testimony on behalf of AES Indiana in previous FAC proceedings as well as ECCRA and TDSIC proceedings. I also submitted testimony in AES Indiana's basic rates cases, Cause Nos. 45029 and 45911.

**Q7. What are your responsibilities in connection with the Applicant's fuel cost filings?**

A7. The data is assembled, and the actual calculations of the fuel cost credit or charge are made under my supervision and direction. In this case, I am presenting the calculated fuel cost factor the Company proposes to place into effect, subject to reconciliation and true-up in a future FAC filing.

**Q8. Have you reviewed the testimony and attachments of the Applicant's other witness in this Cause?**

A8. Yes.

**Q9. Are you sponsoring any attachments?**

A9. Yes. I am sponsoring the following attachments, which were prepared or assembled by me or under my direction and supervision:

- <u>Attachment NHC-l</u> is a copy of the Verified Application filed in this proceeding, including Schedules 1 through 7 thereto reflecting the proposed factor.
- <u>Attachment NHC-1-A</u> are the proposed tariff sheets reflecting the fuel cost adjustment requested herein.
- <u>Attachment NHC-2</u> is a Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended April 30, 2025.
- <u>Attachment NHC-3</u> is a Determination of Authorized Return for the Twelve Months Ended April 30, 2025.
- <u>Attachment NHC-4</u> is an Earnings Test Summary.

**Q10. Is the information set forth in <u>Attachments NHC-l through NHC-4</u> and <u>Attachment NHC-1-A</u> true and correct?**

A10. Yes, to the best of my knowledge.

**Q11. Are you filing any workpapers in this proceeding?**

A11. Yes. I have included Excel workbooks that support the calculations of <u>Attachments NHC-1</u> through <u>Attachment NHC-4</u>.

**Q12. Have you reviewed the Commission's June 1, 2005 Order in Cause No. 42685 ("June 1, 2005 Order") and June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II**

**Order") regarding changes in operations as a result of the Midcontinent Independent System Operator Inc.'s ("MISO") implementation of energy markets and for determination of the manner and timing of recovery costs resulting from the implementation of standard market design mechanisms and participation in the ancillary services market?**

A12. Yes.

**Q13. Is AES Indiana's filing in this proceeding consistent with your understanding of these two orders?**

A13. Yes, AES Indiana's filing in this proceeding is consistent with my understanding of the Commission's June 1, 2005 Order and Phase II Order.

**Q14. Over what months has the Applicant estimated its fuel costs in <u>Attachment NHC-1</u> for the purpose of its proposed fuel cost factor for electric service?**

A14. <u>Attachment NHC-1</u> estimates fuel costs over the months of September through November 2025 (the "Forecast Period").

**Q15. In making such estimates, were actual fuel costs reconciled with estimated fuel costs for any period?**

A15. Yes, actual fuel costs for the months of February through April 2025 (the "Historical Period") were reconciled with the estimated fuel costs for the same period. These variances are shown for reference in the FAC factor calculated on <u>Attachment NHC-1</u>, Schedule 5 and the reconciliations are included in the proposed factor on <u>Attachment NHC-1</u>, Schedule 1.

**Q16. Have calculations been made applying the Purchased Power Daily Benchmarks established pursuant to the methodology approved in Cause No. 43414?**

A16. Yes. As described in the testimony of AES Indiana Witness Dickerson, the applicable Purchased Power Daily Benchmarks are set forth in Attachment AD-1 and have been done in conformity with the Commission's Order in Cause No. 43414.

**Q17. Is AES Indiana seeking to recover the costs of any individual purchased power transactions used to serve jurisdictional retail customers in excess of the applicable Purchased Power Daily Benchmarks?**

A17. Yes. As described in the testimony of AES Indiana Witness Dickerson, the Company is seeking to recover $231,721 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks for the Historical Period. A summary of the purchased power volumes, costs, the total 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 to AES Indiana Witness Dickerson's testimony.

**Q18. Did AES Indiana include in this filing the fuel cost and fuel revenues associated with sales from its public electric vehicle charging stations during the Historical Period?**

A18. Yes. AES Indiana determined the fuel cost for its public electric vehicle charging stations by multiplying the total public electric vehicle charging station kWh sales by the average cost of fuel per kWh for each period. AES Indiana calculated the fuel portion of electric vehicle revenues by multiplying the total public electric vehicle charging station kWh sales under Rate EVP by the applicable fuel factor in effect. The amounts accounted for as fuel costs are reflected on Attachment NHC-1, Schedule 4, Line 4, columns E and F. The recovery represents a reduction in the fuel costs collected through this FAC filing.

**Q19. Did AES Indiana incur any realized gains or losses associated with financial hedges or transactional fees for the hedging program?**

A19. No. There were no financial hedges settled, or transactional fees incurred, during the Historical Period as shown on Attachment NHC-1, Schedule 5, Line 21. As I explained in my testimony in FAC 122, physical hedges do not receive mark-to-market accounting treatment and thus there are no recognized gains or losses on physical hedges. See Witness Dickerson's testimony for a discussion of the result of any physical hedges.

**Q20. Are you familiar with the Applicant's estimated and actual fuel costs for the months of February through April 2025?**

A20. Yes. As shown in Attachment NHC-l, Schedule 5 (Page 4 of 4), the estimated fuel cost for those months was \$0.035600 per kWh and the actual cost for the same period averaged \$0.038011 per kWh, which represents an underestimate of 6.34%. Witness Dickerson discusses the primary drivers for the variance in his testimony.

**Q21. Based on such costs, in your opinion, are Applicant's estimated average fuel costs for the months of September through November 2025, as set forth in Attachment NHC-1, reasonable in amount?**

A21. Yes. The estimated fuel costs for those months reflect the expected costs from contract sources. The Company has also included forecasted costs associated with participation in MISO, spot purchases of fuel, purchased power from renewable resources, and other fuel costs.

**Q22. When was the last Order of the Commission approving Applicant's basic electric rates and charges?**

A22. On April 17, 2024, the Commission issued an order in Cause No. 45911 (the "2024 Base Rate Order") approving new basic rates and charges based on Applicant's test year operating expenses and operating income for the twelve months ended December 31, 2022. Nunc Pro Tunc orders were issued on April 24, 2024 and April 30, 2024. AES Indiana implemented the new base rates on a service rendered basis effective May 9, 2024. The 2024 Base Rate Order established an annual level of operating income of $235,972,000.[1] Prior to April 17, 2024 the last order of the Commission approving Applicant's basic rates and charges was Cause No. 45029 (the "2018 Base Rate Order") which approved new basic rates and charges based on Applicant's test year expenses and operating income for the twelve months ended June 30, 2017. The 2018 Base Rate Order established an annual level of operating income of $220,076,000.

**Q23. Did AES Indiana make any other changes to this filing as a result of the 2024 Base Rate Order?**

A23. Yes. As described in the prior filing, AES Indiana made the following changes based on the 2024 Base Rate Order are also reflected in this FAC filing.

- <u>Attachment NHC-3</u> was updated in three ways to reflect the impact of the 2024 Base Rate Order on AES Indiana's authorized operating income:

    i. First, the base amount of authorized operating income was prorated on a monthly basis, consistent with how the 2024 Base Rate Order impacted

[1] See April 24, 2024 Nunc Pro Tunc Order in Cause No. 45911.

AES Indiana's accounting records. As a result of new base rates being implemented on May 9, 2024, eight days of the authorized operating income of $220,076,000 as approved in the 2018 Base Rate Order was included, as well as eleven months and twenty three days of the authorized operating income of $235,972,000 as approved in the 2024 Base Rate Order for the twelve-month net operating income period ending April 30, 2025.

ii. Second, the allowed return on clean coal technology ("CCT") utility plant is added to the authorized operating income was adjusted to reflect "pre-rate case" and "post-rate case" return based on the environmental projects that rolled into AES Indiana's base rates beginning May 9, 2024. This adjustment is necessary to avoid a mismatch with the Environmental Compliance Cost Recovery Adjustment ("ECCRA" or "ECR") 37 factors, which were updated to reflect the roll-in to base rate effective on a service rendered basis beginning May 9. 2024.

iii. Third, the allowed return on Transmission, Distribution and Storage System Improvement Chage ("TDSIC") utility plant that is added to the authorized operating income was adjusted to reflect "pre-rate case" and "post-rate case" return based on the TDSIC projects (in-service as of December 31, 2022) that rolled into AES Indiana's base rates beginning May 9, 2024. This adjustment is necessary to avoid a mismatch with TDSIC 7 factors, which were updated to reflect the roll-in to base rates effective on a service rendered basis beginning May 9. 2024.

**Q24. Please explain <u>Attachments NHC-2, NHC-3, and NHC-4</u>.**

A24. Attachment NHC-2 contains a comparison of AES Indiana's electric retail operating results per books for the Twelve Months Ended April 30, 2025, with the electric operating results applicable to jurisdictional retail customers for the same period. Attachment NHC-2 calculates the result of the "operating expense" test of I.C. § 8-1-2-42(d)(2). This attachment also calculates the I.C. § 8-1-2-42(d)(3) test, to determine if the Applicant's actual return applicable to jurisdictional retail customers for the Twelve Months Ended April 30, 2025, was higher than the authorized net electric operating income during the same period. Attachment NHC-3 calculates AES Indiana's authorized return. That total authorized return was $280,069,000. In accordance with 170 IAC 4-6-21 and the Commission's Orders in Cause Nos. 42170, 45264, 45493/45493 S1, 45591/45832, and 45920, AES Indiana added the return on its Qualified Pollution Control Property ("QPCP") and renewable projects of $34,178,000 and the return on its TDSIC of $9,944,000 (for a total of $44,122,000) to its authorized net operating income of $235,947,000. Attachment NHC-4 reflects the earnings bank total for the relevant period and calculates the differential between the determined return and the authorized return.

**Q25. Based on the calculation on Attachment NHC-2, has AES Indiana passed the "operating expense" test of I.C. § 8-1-2-42(d)(2)?**

A25. Yes. As shown on Attachment NHC-2, the total jurisdictional operating expenses excluding fuel costs have increased as compared to the last basic rate case. Therefore, the Commission should find that the (d)(2) test is satisfied.

**Q26. Based on the calculation on Attachment NHC-2, Attachment NHC-3 and Attachment NHC-4 has AES Indiana passed the I.C. § 8-1-2-42(d)(3) test?**

A26. Yes. Applicant's actual return was more than its authorized return for the Twelve Months Ended April 30, 2025; however, the sum of AES Indiana's differentials for the relevant period is less than zero as shown on Attachment NHC-4. Accordingly, no reduction in the fuel factor is required and the Commission should find that the "return" test of I.C. § 8-1-2-42.3 is satisfied. The Company's actual return applicable to jurisdictional retail customers for the Twelve Months Ended April 30, 2025, was $289,118,000, while the authorized net electric operating income during the same period was $280,069,000 as shown on Attachment NHC-4.

**Q27. Were there any revenue and/or expenses eliminated or excluded from total electric operating income for the Twelve Months Ended April 30, 2025, in the preparation of Applicant's Attachment NHC-2?**

A27. No. AES Indiana did not eliminate or exclude any revenue and/or expenses from the total electric income for the Twelve Months Ended April 30, 2025.

**Q28. What was the source of the data contained in Attachment NHC-2?**

A28. All the accounting figures and other financial data contained in Attachment NHC-2 were derived from AES Indiana's accounting records.

**Q29. Are there any items included in this FAC proceeding as a result of any joint venture renewable projects?**

A29. Yes. The Hardy Hills solar project and associated ratemaking were approved in Cause No. 45493 and reached full commercial operations date on May 1, 2024. In addition, the Pike County Battery Storage System project and associated ratemaking were approved in Cause No. 45920 and reached full commercial date on March 3, 2025. Per the order in Cause No. 45920, AES Indiana is authorized to recover costs incurred pursuant to the contract for differences ("CfD") through a rate adjustment mechanism to be administered through AES Indiana's FAC proceeding (or successor mechanism). The Commission's Order further stated this recovery shall not be subject to any Ind. Code § 8-1-2-42(d) tests or FAC benchmarks.[2]

The CfD invoiced monthly charges and receipts for these projects are reflected on Attachment NHC-1 Schedule 4, lines 11 through 14. These amounts are added to the fuel cost variance calculated on this same attachment. The grand total of the fuel cost variance including CfD and cash receipts then flows to Attachment NHC-1 Schedule 1, line 33. Monthly amounts for these transactions will be included in each FAC proceeding going forward.

**Q30. What is the Applicant's estimated average cost of fuel for the Forecast Period as included in the proposed factor?**

A30. The Applicant's estimated average cost of fuel for the Forecast Period, after taking into consideration the reconciliation of its estimated and actual fuel costs is estimated to be $0.042929 per kWh as shown on Attachment NHC-1, Schedule 1, Page 1 of 1, line 36. This represents a difference of $0.003902 per kWh from the base cost of fuel approved in the most recent rate case (Cause No. 45911) of $0.039027 per kWh.

**Q31. What effect will the proposed factor have on a residential customer using 1,000 kWh per month?**

[2] Cause No. 45920, Order at 25.

A31. Compared to the approved FAC 147 factor, the proposed factor will result in an increase of $2.68 or 1.94% for a residential customer using 1,000 kWh per month. Refer to AES Indiana witness Dickerson's Testimony for a discussion of the impacts to fuel costs.[3]

**Q32. If approved by the Commission, when does the Applicant propose to make effective for electric service the proposed fuel cost factor requested in this proceeding?**

A32. The Applicant seeks to make the fuel cost factor shown in Attachment NHC-1, Schedule 1, line 38 effective for all bills rendered for electric services beginning with the first billing cycles for the September 2025 billing month (Regular Billing District 41 and Special Billing District 01, which begins August 29, 2025). Such adjustment factor, upon becoming effective, shall remain in effect for approximately three (3) months or until replaced by a different adjustment factor. A copy of the proposed tariff is set forth in Attachment NHC-1-A, attached hereto and made a part hereof.

**Q33. Does that conclude your prefiled direct testimony?**

A33. Yes.

[3] See Q/As 18 and 50.

# VERIFICATION

I, Natalie Herr Coklow, Director in Regulatory Accounting for AES US Services, LLC, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated this 16th day of June 2025.

Natalie Herr Coklow

Natalie Herr Coklow

FILED
June 16, 2025
INDIANA UTILITY
REGULATORY COMMISSION

**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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|---|---|---|
| **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 SEPTEMBER 2025 THROUGH NOVEMBER 2025, 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 148** |

**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 September 2025 through November 2025 (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 February 2025 through April 2025 (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 $239,894 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in the Historical Period, of which $8,172 is not recoverable. Applicant is therefore requesting recovery of $231,721 in purchased power costs. 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 \$0.042929 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 is \$0.003902. This factor would represent an increase from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of September 2025 through November 2025.

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)
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13. Applicant requests that the Commission approve the following procedural schedule agreed to by the Applicant and the OUCC in lieu of conducting a prehearing conference. The agreed schedule is as follows:

| **Date** | **Event** |
|---|---|
| July 21, 2025 | OUCC/Intervenors File Case-in-Chief |
| July 31, 2025 | Petitioner's Rebuttal Testimony |
| Week of August 11, 2025 | Hearing |
| August 27, 2025 | 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 September 2025 (Regular Billing District 41 and Special Billing District 01), which begins August 29, 2025. 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 Attachment NHC-1-A;

(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

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 16th day of June, 2025.

Natalie Herr Coklow

Natalie Herr Coklow

# Attachment NHC-1-A

STANDARD CONTRACT RIDER NO. 6
FUEL COST ADJUSTMENT
(Applicable to Rates RS, UW, CW, SS, 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:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.039027$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of ~~June~~ September 2025 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 billed and the incremental fuel cost actually experienced during the months of ~~November 2024 through January 2025~~February 2025 through April 2025.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~June~~ September 2025 (Regular Billing District 41 and Special Billing Route 01) will be $~~0.001223~~0.003902 per KWH.

STANDARD CONTRACT RIDER NO. 6
FUEL COST ADJUSTMENT
(Applicable to Rates RS, UW, CW, SS, 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:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.039027$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of September 2025 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 billed and the incremental fuel cost actually experienced during the months of February 2025 through April 2025.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for September 2025 (Regular Billing District 41 and Special Billing Route 01) will be $0.003902 per KWH.

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 1**
**Page 1 of 1**

**AES INDIANA**
**Determination of Fuel Cost Adjustment**
**Beginning with September 2025 Based on the Estimated**
**Three Months Average of September, October and November 2025**

| Line No. | Description | (A) Estimated Month of: September | (B) Estimated Month of: October | (C) Estimated Month of: November | (D) Total | (E) Estimated Three Month Average | Line No. |
|---|---|---|---|---|---|---|---|
| | **kWh Source (000's)** | | | | | | |
| 1 | Coal and Oil Generation | 548,612 | 611,974 | 616,154 | 1,776,740 | 592,247 | 1 |
| 2 | Nuclear Generation | - | - | - | - | - | 2 |
| 3 | Hydro Generation | - | - | - | - | - | 3 |
| 4 | Other Generation - Internal Combustion | - | - | - | - | - | 4 |
| 5 | Gas Generation | 716,373 | 760,201 | 578,849 | 2,055,423 | 685,141 | 5 |
| 6 | Wind Generation | 14,006 | 20,552 | 24,912 | 59,470 | 19,823 | 6 |
| | Purchases through MISO: | | | | | | |
| 7 | Wind Purchase Power Agreement Purchases | 37,359 | 41,563 | 46,740 | 125,663 | 41,888 | 7 |
| 8 | Non-Wind PPA Market Purchases | 76,309 | 6,126 | 37,586 | 120,020 | 40,007 | 8 |
| 9 | Other | - | - | - | - | - | 9 |
| 10 | Purchased Power other than MISO | 14,894 | 12,384 | 12,056 | 39,334 | 13,111 | 10 |
| | LESS: | | | | | | |
| 11 | Energy Losses and Company Use | 45,494 | 40,561 | 44,508 | 130,562 | 43,521 | 11 |
| 12 | Inter-System Sales through MISO | 286,941 | 453,688 | 219,971 | 960,600 | 320,200 | 12 |
| 13 | Inter-System Sales other than MISO | - | - | - | - | - | 13 |
| 14 | Non-Jurisdictional Retail Sales | - | - | - | - | - | 14 |
| 15 | **Sales (S)** | 1,075,118 | 958,551 | 1,051,819 | 3,085,488 | 1,028,496 | 15 |
| | **Fuel Cost ($)** | | | | | | |
| 16 | Coal and Oil Generation | 14,063,591 | 15,401,587 | 15,388,361 | 44,853,539 | 14,951,180 | 16 |
| 17 | Nuclear Generation | - | - | - | - | - | 17 |
| 18 | Hydro Generation | - | - | - | - | - | 18 |
| 19 | Other Generation - Internal Combustion | - | - | - | - | - | 19 |
| 20 | Gas Generation | 25,009,236 | 26,310,183 | 22,495,330 | 73,814,749 | 24,604,916 | 20 |
| | Purchases through MISO: | | | | | | |
| 21 | Wind Purchase Power Agreement Purchases | 3,945,769 | 4,994,757 | 5,513,702 | 14,454,229 | 4,818,076 | 21 |
| 22 | Non-Wind PPA Market Purchases | 2,085,060 | 185,987 | 1,234,783 | 3,505,831 | 1,168,610 | 22 |
| 23 | Other | - | - | - | - | - | 23 |
| 24 | MISO Components of Cost of Fuel | 1,270,790 | 1,133,007 | 1,243,250 | 3,647,047 | 1,215,682 | 24 |
| 25 | Purchased Power other than MISO | 2,422,710 | 2,001,450 | 1,924,930 | 6,349,090 | 2,116,363 | 25 |
| | Less: | | | | | | |
| 26 | Inter-System Sales through MISO | 7,840,522 | 12,082,340 | 5,969,474 | 25,892,336 | 8,630,779 | 26 |
| 27 | Inter-System Sales other than MISO | - | - | - | - | - | 27 |
| 28 | Non-Jurisdictional Retail Sales | - | - | - | - | - | 28 |
| 29 | Transmission Losses | 423,029 | 367,597 | 411,031 | 1,201,657 | 400,552 | 29 |
| 30 | Lakefield PPA Adjustment | - | - | - | - | - | 30 |
| 31 | **Total Fuel Cost (F)** | $ 40,533,606 | $ 37,577,035 | $ 41,419,851 | $ 119,530,492 | $ 39,843,496 | 31 |
| 32 | **F ÷ S (Line 31 ÷ Line 15) (Mills/kWh)** | | | | | 38.740 | 32 |
| | | Months to be Reconciled: February | March | April | Total | | |
| 33 | Fuel Cost Variance (includes Joint Venture CfD and Cash Receipts) | $ 5,376,583 | $ 4,298,094 | $ 3,249,792 | $ 12,924,469 | | 33 |
| 34 | Total Fuel Cost Variance and Adjustments Included in this Filing | | | | | $ 12,924,469 | 34 |
| | **(Mills/kWh)** | | | | | | |
| 35 | Variance Charge (Line 34 Total divided by estimated Indiana jurisdictional sales of | | 3,085,488 kWh (000's) | | | 4.189 | 35 |
| 36 | Adjusted Fuel Cost Charge (Line 32 + Line 35) | | | | | 42.929 | 36 |
| 37 | Less: Base Cost of Fuel Included in Rates | | | | | 39.027 | 37 |
| 38 | Fuel Cost Charge | | | | | 3.902 | 38 |

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 2**
**Page 1 of 1**

**AES INDIANA**
**Determination of Net Energy Cost of Purchased Power**
**For the Estimated Months of September, October and November 2025**

| Line No | Supplier | kWh Purchased (000's) | Energy * | Line No |
|---|---|---|---|---|
| | | (A) | (B) | |
| | September | | | |
| | Purchases through MISO: | | | |
| 1 | Wind Purchase Power Agreement Purchases | 37,359 | $ 3,945,769 | 1 |
| 2 | Non-Wind PPA Market Purchases | 76,309 | 2,085,060 | 2 |
| 3 | Other | - | - | 3 |
| 4 | MISO Components of Cost of Fuel | - | 1,270,790 | 4 |
| 5 | Purchased Power other than MISO | 14,894 | 2,422,710 | 5 |
| 6 | Total | 128,562 | $ 9,724,329 | 6 |
| | October | | | |
| | Purchases through MISO: | | | |
| 7 | Wind Purchase Power Agreement Purchases | 41,563 | $ 4,994,757 | 7 |
| 8 | Non-Wind PPA Market Purchases | 6,126 | 185,987 | 8 |
| 9 | Other | - | - | 9 |
| 10 | MISO Components of Cost of Fuel | - | 1,133,007 | 10 |
| 11 | Purchased Power other than MISO | 12,384 | 2,001,450 | 11 |
| 12 | Total | 60,073 | $ 8,315,202 | 12 |
| | November | | | |
| | Purchases through MISO: | | | |
| 13 | Wind Purchase Power Agreement Purchases | 46,740 | $ 5,513,702 | 13 |
| 14 | Non-Wind PPA Market Purchases | 37,586 | 1,234,783 | 14 |
| 15 | Other | - | - | 15 |
| 16 | MISO Components of Cost of Fuel | - | 1,243,250 | 16 |
| 17 | Purchased Power other than MISO | 12,056 | 1,924,930 | 17 |
| 18 | Total | 96,382 | $ 9,916,665 | 18 |
| 19 | Total Net Energy Cost of Purchased Power | 285,017 | $ 27,956,196 | 19 |

* Demand Charges have not been estimated.

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 3**
**Page 1 of 1**

**AES INDIANA**
**Determination of Fuel Costs Recovered Through**
**Inter-System and Non-Jurisdictional Retail Sales by Month**
**For the Estimated Months of September, October and November 2025**

| Line No. | Purchaser | kWh Sold (000's) (A) | Fuel Cost * (B) | Line No. |
|---|---|---|---|---|
| | **September** | | | |
| 1 | Inter-System Sales through MISO | 286,941 | $ 7,840,522 | 1 |
| 2 | Inter-System Sales other than MISO | - | - | 2 |
| 3 | Non-Jurisdictional Retail Sales | - | - | 3 |
| 4 | Total | 286,941 | $ 7,840,522 | 4 |
| | **October** | | | |
| 5 | Inter-System Sales through MISO | 453,688 | $ 12,082,340 | 5 |
| 6 | Inter-System Sales other than MISO | - | - | 6 |
| 7 | Non-Jurisdictional Retail Sales | - | - | 7 |
| 8 | Total | 453,688 | $ 12,082,340 | 8 |
| | **November** | | | |
| 9 | Inter-System Sales through MISO | 219,971 | $ 5,969,474 | 9 |
| 10 | Inter-System Sales other than MISO | - | - | 10 |
| 11 | Non-Jurisdictional Retail Sales | - | - | 11 |
| 12 | Total | 219,971 | $ 5,969,474 | 12 |
| 13 | Total Inter-System and Non-Jurisdictional Retail Sales | 960,600 | $ 25,892,336 | 13 |

* Demand Charges have not been estimated.

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1
Schedule 4
Page 1 of 3**

**AES INDIANA
Reconciliation of Actual Incremental Cost of Fue
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for February 2025**

| Line No. | Class of Customers | kWh Sales (In 000's) | Base Cost of Fuel Included in Rates 39.027 Mills/kWh | Actual Cost of Fuel Incurred 41.294 Mills/kWh | Actual Incremental Cost of Fuel Incurred | Actual Incremental Cost of Fuel Billed | Fuel Cost [1] Variance From Cause No. 38703-FAC145 | Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred | Fuel Cost Variance | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) (Col A * mills above) | (C) (Col A * mills above) | (D) (Col C - Col B) | (E) | (F) | (G) (Col E - Col F) | (H) (Col D - Col G) | |
| 1 | Total Residential | 590,493 | $ 23,045,170 | $ 24,383,815 | $ 1,338,645 | $ (763,375) | | | | 1 |
| 2 | Total Commercial | 181,864 | 7,097,606 | 7,509,892 | 412,286 | (237,043) | | | | 2 |
| 3 | Total Industrial | 502,665 | 19,617,507 | 20,757,049 | 1,139,542 | (650,580) | | | | 3 |
| 4 | Total Electric Vehicle Public Charging Stations | 6 | 234 | 248 | 14 | (7) | | | | 4 |
| 5 | Total Lighting | 3,362 | 131,209 | 138,830 | 7,621 | (4,383) | | | | 5 |
| 6 | Total Other | | | | | | | | | 6 |
| 7 | Total Retail Sales Subject to FAC | 1,278,390 | $ 49,891,726 | $ 52,789,834 | $ 2,898,108 | $ (1,655,388) | $ 509,350 | $ (2,164,738) | $ 5,062,846 | 7 |
| 8 | Total Retail Sales NOT Subject to FAC | - | | | | | | | | 8 |
| 9 | Total Non-jurisdictional Retail Sales | - | | | | | | | | 9 |
| 10 | Sales | 1,278,390 | | | | | | | | 10 |
| 11 | Hardy Hills Contract for Differences (CfD) | | | | | | | | 453,737 | 11 |
| 12 | Hardy Hills Cash Receipts | | | | | | | | (140,000) | 12 |
| 13 | Fuel Cost Variance with CfD and Receipts | | | | | | | | $ 5,376,583 | 13 |

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 145 $1,528,049, or $509,350 per month.

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 4**
**Page 2 of 3**

**AES INDIANA**
**Reconciliation of Actual Incremental Cost of Fuel**
**Incurred to Applicable Incremental Retail Fuel Clause**
**Revenues for March 2025**

| 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 36.476 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-FAC146 (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 | 437,587 | $ 17,077,706 | $ 15,961,423 | $ (1,116,283) | $ (2,323,221) | | | | 1 |
| 2 | Total Commercial | 147,765 | 5,766,825 | 5,389,876 | (376,949) | (778,761) | | | | 2 |
| 3 | Total Industrial | 436,303 | 17,027,597 | 15,914,588 | (1,113,009) | (2,143,164) | | | | 3 |
| 4 | Total Electric Vehicle Public Charging Stations | 4 | 156 | 146 | (10) | (22) | | | | 4 |
| 5 | Total Lighting | 10,303 | 402,095 | 375,812 | (26,283) | (41,472) | | | | 5 |
| 6 | Total Other | | | | | | | | | 6 |
| 7 | Total Retail Sales Subject to FAC | 1,031,962 | $ 40,274,379 | $ 37,641,845 | $ (2,632,534) | $ (5,286,640) | $ (1,355,364) | $ (3,931,276) | $ 1,298,742 | 7 |
| 8 | Total Retail Sales NOT Subject to FAC | - | | | | | | | | 8 |
| 9 | Total Non-jurisdictional Retail Sales | - | | | | | | | | 9 |
| 10 | Sales | 1,031,962 | | | | | | | | 10 |
| 11 | Hardy Hills Contract for Differences (CfD) | | | | | | | | 816,342 | 11 |
| 12 | Hardy Hills Cash Receipts | | | | | | | | (350,000) | 12 |
| 13 | Pike BESS Contract for Differences (CfD) | | | | | | | | 2,815,584 | 13 |
| 14 | Pike BESS Cash Receipts | | | | | | | | (282,574) | 14 |
| 15 | Fuel Cost Variance with CfD and Receipts | | | | | | | | $ 4,298,094 | 15 |

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 146 ($4,066,093), or ($1,355,364) per month.

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 4**
**Page 3 of 3**

**AES INDIANA**
**Reconciliation of Actual Incremental Cost of Fuel**
**Incurred to Applicable Incremental Retail Fuel Clause**
**Revenues for April 2025**

| 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 35.693 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-FAC146 (F) | Incremental 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 | 356,419 | $ 13,909,964 | $ 12,721,663 | $ (1,188,301) | $ (1,899,203) | | | | 1 |
| 2 | Total Commercial | 130,798 | 5,104,654 | 4,668,573 | (436,081) | (702,304) | | | | 2 |
| 3 | Total Industrial | 483,627 | 18,874,511 | 17,262,099 | (1,612,412) | (2,577,833) | | | | 3 |
| 4 | Total Electric Vehicle Public Charging Stations | 5 | 195 | 178 | (17) | (28) | | | | 4 |
| 5 | Total Lighting | 5,105 | 199,233 | 182,213 | (17,020) | (27,256) | | | | 5 |
| 6 | Total Other | | | | | | | | | 6 |
| 7 | Total Retail Sales Subject to FAC | 975,954 | $ 38,088,557 | $ 34,834,726 | $ (3,253,831) | $ (5,206,624) | $ (1,355,364) | $ (3,851,260) | $ 597,429 | 7 |
| 8 | Total Retail Sales NOT Subject to FAC | - | | | | | | | | 8 |
| 9 | Total Non-jurisdictional Retail Sales | - | | | | | | | | 9 |
| 10 | Sales | 975,954 | | | | | | | | 10 |
| 11 | Hardy Hills Contract for Differences (CfD) | | | | | | | | 896,245 | 11 |
| 12 | Hardy Hills Cash Receipts | | | | | | | | (945,000) | 12 |
| 13 | Pike BESS Contract for Differences (CfD) | | | | | | | | 2,712,056 | 13 |
| 14 | Pike BESS Cash Receipts | | | | | | | | (10,938) | 14 |
| 15 | Fuel Cost Variance with CFD and Distributions | | | | | | | | $ 3,249,792 | 15 |

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 146 ($4,066,093), or ($1,355,364) per month.

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 5**
**Page 1 of 4**

**AES INDIANA**
**Comparison of Actual and Estimated Cost of Fuel**
**Reconciliation February 2025**

| Line No. | Description | February Actual | February Forecast | Line No. |
|---|---|---|---|---|
| | kWh Source (000's) | | | |
| 1 | Coal and Oil Generation | 428,563 | 617,088 | 1 |
| 2 | Nuclear Generation | - | - | 2 |
| 3 | Hydro Generation | - | - | 3 |
| 4 | Other Generation - Internal Combustion | 10 | - | 4 |
| 5 | Gas Generation | 642,548 | 830,954 | 5 |
| 6 | Wind Generation | 17,722 | 24,132 | 6 |
| | Purchases through MISO: | | | |
| 7 | Wind Purchase Power Agreement Purchases | 41,323 | 47,636 | 7 |
| 8 | Non-Wind PPA Market Purchases | 106,548 | 5,768 | 8 |
| 9 | Other | 1,044 | - | 9 |
| 10 | Purchased Power other than MISO | 7,581 | 7,458 | 10 |
| | LESS: | | | |
| 11 | Energy Losses and Company Use | 55,280 | 53,242 | 11 |
| 12 | Inter-System Sales through MISO | 71,086 | 332,470 | 12 |
| 13 | Inter-System Sales other than MISO | - | - | 13 |
| 14 | Non-Jurisdictional Retail Sales | - | - | 14 |
| 15 | Sales (S) | 1,118,973 | 1,147,323 | 15 |
| | Fuel Cost | | | |
| 16 | Coal and Oil Generation | $ 12,122,070 | $ 15,072,572 | 16 |
| 17 | Nuclear Generation | - | - | 17 |
| 18 | Hydro Generation | - | - | 18 |
| 19 | Other Generation - Internal Combustion | 2,634 | - | 19 |
| 20 | Gas Generation | 26,613,412 | 28,935,113 | 20 |
| 21 | Financial Hedges Gains/Losses & Transactional Fees | - | - | 21 |
| | Purchases through MISO: | | | |
| 22 | Wind Purchase Power Agreement Purchases | 4,653,541 | 4,951,318 | 22 |
| 23 | Non-Wind PPA Market Purchases | 3,481,980 | 261,153 | 23 |
| 24 | Other | 37,361 | - | 24 |
| 25 | MISO Components of Cost of Fuel | 828,660 | 1,535,119 | 25 |
| 26 | Purchased Power other than MISO | 1,238,768 | 1,182,840 | 26 |
| | LESS: | | | |
| 27 | Inter-System Sales through MISO | 2,506,958 | 9,122,156 | 27 |
| 28 | Inter-System Sales other than MISO | - | - | 28 |
| 29 | Non-Jurisdictional Retail Sales | - | - | 29 |
| 30 | Transmission Losses | 259,471 | 453,307 | 30 |
| 31 | Lakefield PPA Adjustment | - | - | 31 |
| 32 | Purchased Power in Excess | 4,850 | - | 32 |
| 33 | Total Fuel Costs (F) | $ 46,207,147 | $ 42,362,652 | 33 |
| 34 | F / S (Mills/kWh) | 41.294 | 36.923 | 34 |
| | Weighted Average Deviation | -10.59% | | |

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 5**
**Page 2 of 4**

**AES INDIANA**
**Comparison of Actual and Estimated Cost of Fuel**
**Reconciliation March 2025**

| Line No. | Description | March Actual | March Forecast | Line No. |
|---|---|---|---|---|
| | kWh Source (000's) | | | |
| 1 | Coal and Oil Generation | 432,582 | 356,504 | 1 |
| 2 | Nuclear Generation | - | - | 2 |
| 3 | Hydro Generation | - | - | 3 |
| 4 | Other Generation - Internal Combustion | 10 | - | 4 |
| 5 | Gas Generation | 595,450 | 741,760 | 5 |
| 6 | Wind Generation | 27,493 | 25,858 | 6 |
| | Purchases through MISO | | | |
| 7 | Wind Purchase Power Agreement Purchases | 36,845 | 45,756 | 7 |
| 8 | Non-Wind PPA Market Purchases | 72,645 | 9,794 | 8 |
| 9 | Other | 661 | - | 9 |
| 10 | Purchased Power other than MISO | 10,461 | 80,689 | 10 |
| | LESS: | | | |
| 11 | Energy Losses and Company Use | 49,300 | 49,395 | 11 |
| 12 | Inter-System Sales through MISO | 119,733 | 146,528 | 12 |
| 13 | Inter-System Sales other than MISO | - | - | 13 |
| 14 | Non-Jurisdictional Retail Sales | - | - | 14 |
| 15 | Sales (S) | 1,007,114 | 1,064,438 | 15 |
| | Fuel Cost | | | |
| 16 | Coal and Oil Generation | $ 11,602,475 | $ 9,422,368 | 16 |
| 17 | Nuclear Generation | - | - | 17 |
| 18 | Hydro Generation | - | - | 18 |
| 19 | Other Generation - Internal Combustion | 4,983 | - | 19 |
| 20 | Gas Generation | 16,930,060 | 19,169,575 | 20 |
| 21 | Financial Hedges Gains/Losses & Transactional Fees | - | - | 21 |
| | Purchases through MISO | | | |
| 22 | Wind Purchase Power Agreement Purchases | 6,133,293 | 5,369,169 | 22 |
| 23 | Non-Wind PPA Market Purchases | 2,239,246 | 1,542,010 | 23 |
| 24 | Other | 24,233 | - | 24 |
| 25 | MISO Components of Cost of Fuel | 1,281,361 | 1,366,738 | 25 |
| 26 | Purchased Power other than MISO | 1,713,820 | 2,847,187 | 26 |
| | LESS: | | | |
| 27 | Inter-System Sales through MISO | 2,942,469 | 3,370,267 | 27 |
| 28 | Inter-System Sales other than MISO | - | - | 28 |
| 29 | Non-Jurisdictional Retail Sales | - | - | 29 |
| 30 | Transmission Losses | 249,923 | 352,555 | 30 |
| 31 | Lakefield PPA Adjustment | - | - | 31 |
| 32 | Purchased Power in Excess | 1,284 | - | 32 |
| 33 | Total Fuel Costs (F) | $ 36,735,795 | $ 35,994,225 | 33 |
| 34 | F / S (Mills/kWh) | 36.476 | 33.815 | 34 |
| | Weighted Average Deviation | -7.30% | | |

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 5**
**Page 3 of 4**

**AES INDIANA**
**Comparison of Actual and Estimated Cost of Fuel**
**Reconciliation April 2025**

| Line No. | Description | April Actual | April Forecast | Line No. |
|---|---|---|---|---|
| | kWh Source (000's) | | | |
| 1 | Coal and Oil Generation | 401,048 | 439,735 | 1 |
| 2 | Nuclear Generation | - | - | 2 |
| 3 | Hydro Generation | - | - | 3 |
| 4 | Other Generation - Internal Combustion | - | - | 4 |
| 5 | Gas Generation | 654,954 | 810,169 | 5 |
| 6 | Wind Generation | 25,554 | 19,203 | |
| | Purchases through MISO | | | |
| 7 | Wind Purchase Power Agreement Purchases | 27,177 | 40,683 | 7 |
| 8 | Non-Wind PPA Market Purchases | 56,942 | 13,039 | 8 |
| 9 | Other | 798 | - | 9 |
| 10 | Purchased Power other than MISO | 11,484 | 21,994 | 10 |
| | LESS: | | | |
| 11 | Energy Losses and Company Use | 45,107 | 42,490 | 11 |
| 12 | Inter-System Sales through MISO | 214,248 | 386,708 | 12 |
| 13 | Inter-System Sales other than MISO | - | - | 13 |
| 14 | Non-Jurisdictional Retail Sales | - | - | 14 |
| 15 | Sales (S) | 918,602 | 915,625 | 15 |
| | Fuel Cost | | | |
| 16 | Coal and Oil Generation | $ 11,150,958 | $ 11,245,075 | 16 |
| 17 | Nuclear Generation | - | - | 17 |
| 18 | Hydro Generation | - | - | 18 |
| 19 | Other Generation - Internal Combustion | 3,202 | - | 19 |
| 20 | Gas Generation | 17,888,490 | 22,025,635 | 20 |
| 21 | Financial Hedges Gains/Losses & Transactional Fees | - | - | 21 |
| | Purchases through MISO | | | |
| 22 | Wind Purchase Power Agreement Purchases | 5,414,490 | 5,375,407 | 22 |
| 23 | Non-Wind PPA Market Purchases | 1,599,808 | 2,083,290 | 23 |
| 24 | Other | 29,249 | - | 24 |
| 25 | MISO Components of Cost of Fuel | (87,178) | 1,175,664 | 25 |
| 26 | Purchased Power other than MISO | 1,922,763 | 678,589 | 26 |
| | LESS: | | | |
| 27 | Inter-System Sales through MISO | 4,919,144 | 9,289,168 | 27 |
| 28 | Inter-System Sales other than MISO | - | - | 28 |
| 29 | Non-Jurisdictional Retail Sales | - | - | 29 |
| 30 | Transmission Losses | $212,642 | 316,719 | 30 |
| 31 | Lakefield PPA Adjustment | - | - | 31 |
| 32 | Purchased Power in Excess | 2,038 | - | 32 |
| 33 | Total Fuel Costs (F) | $ 32,787,958 | $ 32,977,773 | 33 |
| 34 | F / S (Mills/kWh) | 35.693 | 36.017 | 34 |
| | Weighted Average Deviation | 0.91% | | |

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 5**
**Page 4 of 4**

**AES INDIANA**
**Comparison of Actual and Estimated Cost of Fuel**
**February, March and April, 2025**

| Line No. | Description | Total Actual | Total Forecast | Line No. |
|---|---|---|---|---|
| | kWh Source (000's) | | | |
| 1 | Coal and Oil Generation | 1,262,193 | 1,413,327 | 1 |
| 2 | Nuclear Generation | - | - | 2 |
| 3 | Hydro Generation | - | - | 3 |
| 4 | Other Generation - Internal Combustion | 20 | - | 4 |
| 5 | Gas Generation | 1,892,952 | 2,382,883 | 5 |
| 6 | Wind Generation | 70,769 | 69,193 | |
| | Purchases through MISO | | | |
| 7 | Wind Purchase Power Agreement Purchases | 105,345 | 134,075 | 7 |
| 8 | Non-Wind PPA Market Purchases | 236,135 | 28,601 | 8 |
| 9 | Other | 2,503 | - | 9 |
| 10 | Purchased Power other than MISO | 29,526 | 110,141 | 10 |
| | LESS: | | | |
| 11 | Energy Losses and Company Use | 149,687 | 145,127 | 11 |
| 12 | Inter-System Sales through MISO | 405,067 | 865,706 | 12 |
| 13 | Inter-System Sales other than MISO | - | - | 13 |
| 14 | Non-Jurisdictional Retail Sales | - | - | 14 |
| 15 | Sales (S) | 3,044,689 | 3,127,386 | 15 |
| | Fuel Cost | | | |
| 16 | Coal and Oil Generation | $ 34,875,503 | $ 35,740,015 | 16 |
| 17 | Nuclear Generation | - | - | 17 |
| 18 | Hydro Generation | - | - | 18 |
| 19 | Other Generation - Internal Combustion | 10,819 | - | 19 |
| 20 | Gas Generation | 61,431,962 | 70,130,323 | 20 |
| 21 | Financial Hedges Gains/Losses & Transactional Fees | - | - | 21 |
| | Purchases through MISO | | | |
| 22 | Wind Purchase Power Agreement Purchases | 16,201,324 | 15,695,894 | 22 |
| 23 | Non-Wind PPA Market Purchases | 7,321,034 | 3,886,453 | 23 |
| 24 | Other | 90,843 | - | 24 |
| 25 | MISO Components of Cost of Fuel | 2,022,843 | 4,077,521 | 25 |
| 26 | Purchased Power other than MISO | 4,875,351 | 4,708,616 | 26 |
| | LESS: | | | |
| 27 | Inter-System Sales through MISO | 10,368,571 | 21,781,591 | 27 |
| 28 | Inter-System Sales other than MISO | - | - | 28 |
| 29 | Non-Jurisdictional Retail Sales | - | - | 29 |
| 30 | Transmission Losses | 722,036 | 1,122,581 | 30 |
| 31 | Lakefield PPA Adjustment | - | - | 31 |
| 32 | Purchased Power in Excess | 8,172 | - | 32 |
| 33 | Total Fuel Costs (F) | $ 115,730,900 | $ 111,334,650 | 33 |
| 34 | F / S (Mills/kWh) | 38.011 | 35.600 | 34 |
| | Weighted Average Deviation | -6.34% | | |

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 6**
**Page 1 of 1**

**AES INDIANA**
**Determination of MISO Components of Fuel Cost**
**February, March and April, 2025**

| Line No. | Energy Market FAC Adjustment Components | Total February (A) | Total March (B) | Total April (C) | Line No. |
|---|---|---|---|---|---|
| 1 | Delta LMP[1] | $ 1,520,341 | $ 1,638,940 | $ 1,407,084 | 1 |
| 2 | FTR (Revenue) / Expenses | $ (605,597) | $ (686,832) | $ (1,494,321) | 2 |
| 3 | RT Marg. Loss Surplus Credit | $ (298,090) | $ (27,268) | $ (163,815) | 3 |
| 4 | Virtuals Bids and Offers for Load | $ - | $ - | $ - | 4 |
| 5 | DA & RAC Recovery of Unit Commitment Costs | $ 12,167 | $ (541) | $ (1,081) | 5 |
| 5a | RSG 1st Pass Charges | $ 20,906 | $ 16,462 | $ 13,093 | 5a |
| 5b | RSG 2nd Pass Distribution Correction | $ - | $ - | $ - | 5b |
| 6 | Inadvertent Energy | $ 58,714 | $ 179,910 | $ (232) | 6 |
| 7 | Ancillary Services Revenue | $ (144,689) | $ (24,767) | $ (34,802) | 7 |
| 8 | Ancillary Services Costs | $ 261,871 | $ 173,625 | $ 195,918 | 8 |
| 9 | Ancillary Services Incentive to Follow Dispatch[2] | $ 17,357 | $ 7,103 | $ 6,730 | 9 |
| 10 | Ramp Capability[3] | $ (14,320) | $ 4,729 | $ (15,752) | 10 |
| 11 | MISO Transmission Owner's Payment not on Settlement Statement - credit to FAC. | $ - | $ - | $ - | 11 |
| 12 | Total (Columns A, B, & C to Schedule 5, line 25) | $ 828,660 | $ 1,281,361 | $ (87,178) | 12 |

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

**Cause No. 38703-FAC148**

**Applicant's Attachment NHC-1**
**Schedule 7**
**Page 1 of 1**

**AES INDIANA**
**MISO Charges by Month by Charge Type**

| Line No. | Charge Type | Feb-25 Invoice Total | Mar-25 Invoice Total | Apr-25 Invoice Total | Line No. |
|---|---|---|---|---|---|
| 1 | Day Ahead Market Administration Amount | $ 284,605 | $ 214,146 | $ 241,868 | 1 |
| 2 | Day Ahead Regulation Amount | $ - | - | - | 2 |
| 3 | Day Ahead Spinning Reserve Amount | $ (2,774) | (3,275) | (18,076) | 3 |
| 4 | Day-Ahead Short-Term Reserve Amount | $ - | - | - | 4 |
| 5 | Day Ahead Supplemental Reserve Amount | $ (82,908) | (5,027) | (16,493) | 5 |
| 6 | Day Ahead Asset Energy Amount | $ (3,943,818) | (4,179,787) | (9,482,548) | 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 | $ (36,769) | (21,669) | (39,923) | 14 |
| 15 | Day Ahead Revenue Sufficiency Guarantee Distribution Amount | $ 37,674 | 31,567 | 25,415 | 15 |
| 16 | Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt | $ (23,033) | (33,223) | (29,908) | 16 |
| 17 | Day Ahead Schedule 24 Allocation Amount | $ 34,491 | 31,415 | 32,762 | 17 |
| 18 | Day Ahead Virtual Energy Amount | $ - | - | - | 18 |
| | **Day Ahead Subtotal** | $ (3,732,532) | $ (3,965,853) | $ (9,286,903) | |
| 19 | Financial Transmission Rights Market Administration Amount | $ 4,314 | 5,298 | 2,213 | 19 |
| 20 | Auction Revenue Rights Transaction Amount | $ (697,894) | (228,858) | (228,858) | 20 |
| 21 | Financial Transmission Rights Annual Transaction Amount | $ 464,257 | 199,181 | 199,180 | 21 |
| 22 | Auction Revenue Rights Infeasible Uplift Amount | $ 44,890 | 55,874 | 56,560 | 22 |
| 23 | Auction Revenue Rights Stage 2 Distribution Amount | $ (224,405) | (166,864) | (165,988) | 23 |
| 24 | Financial Transmission Rights Full Funding Guarantee Amount | $ - | - | - | 24 |
| 25 | Financial Transmission Guarantee Uplift Amount | $ - | - | - | 25 |
| 26 | Financial Transmission Rights Hourly Allocation Amount | $ (191,068) | (536,668) | (1,314,073) | 26 |
| 27 | Financial Transmission Rights Monthly Allocation Amount | $ (1,377) | (9,497) | (41,142) | 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** | $ (601,283) | $ (681,534) | $ (1,492,108) | |
| 31 | Real Time Market Administration Amount | 37,010 | 25,505 | 31,727 | 31 |
| 32 | Contingency Reserve Deployment Failure Charge Amount | - | - | - | 32 |
| 33 | Excessive Energy Amount | - | - | - | 33 |
| 34 | Real Time Excessive Deficient Energy Deployment Charge Amount | (39,470) | (14,362) | (8,160) | 34 |
| 35 | Net Regulation Adjustment Amount | 17,140 | 7,188 | 7,523 | 35 |
| 36 | Non-Excessive Energy Amount | - | - | - | 36 |
| 37 | Real Time Regulation Amount | 4,283,598 | 2,385,612 | 4,248,515 | 37 |
| 38 | Regulation Cost Distribution Amount | - | - | - | 38 |
| 39 | Real Time Spinning Reserve Amount | 80,336 | 77,650 | 83,173 | 39 |
| 40 | Spinning Reserve Cost Distribution Amount | (14,355) | (6,054) | 2,252 | 40 |
| 41 | Real Time Short-Term Reserve Amount | 58,115 | 57,319 | 57,154 | 41 |
| 42 | Real-Time Short-Term Reserve Deployment Failure Charge Amount | (1,219) | - | - | 42 |
| 43 | Short-Term Reserve Cost Distribution Amount | 10,365 | 6,625 | 10,640 | 43 |
| 44 | Real Time Supplemental Reserve Amount | (43,432) | (10,411) | (2,485) | 44 |
| 45 | Supplemental Reserve Cost Distribution Amount | 113,057 | 32,029 | 44,951 | 45 |
| 46 | Real Time Asset Energy Amount | 442,832 | 877,579 | 377,906 | 46 |
| 47 | Real Time Demand Response Allocation Uplift Charge | 284 | 3 | 178 | 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 | (298,090) | (27,268) | (163,815) | 52 |
| 53 | Real Time Miscellaneous Amount | (49,253) | (1,112) | 259 | 53 |
| 54 | Real Time MVP Distribution Amount | (45,470) | (78,118) | (29,191) | 54 |
| 55 | Real Time Non-Asset Energy Amount | - | - | - | 55 |
| 56 | Real Time Net Inadvertent Distribution Amount | 58,714 | 179,910 | (232) | 56 |
| 57 | Real Time Price Volatility Make Whole Payment | (339,039) | (338,677) | (425,104) | 57 |
| 58 | Real Time Resource Adequacy Auction Amount | 37,115 | (259,137) | (245,124) | 58 |
| 59 | Real Time Ramp Capability Amount | (8,628) | (9,224) | (10,038) | 59 |
| 60 | Real Time Revenue Neutrality Uplift Amount | 123,885 | 196,834 | 358,877 | 60 |
| 61 | Real Time Revenue Sufficiency Guarantee First Pass Dist Amount | 29,112 | 18,480 | 16,046 | 61 |
| 62 | Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt | (3,005) | (5,420) | (2,746) | 62 |
| 63 | Real-Time Storage as Transmission Only Asset Amount | - | - | - | 63 |
| 64 | Real Time Schedule 24 Allocation Amount | 4,485 | 3,742 | 4,297 | 64 |
| 65 | Real Time Schedule 24 Distribution Amount | (62,040) | (61,350) | (62,302) | 65 |
| 66 | Real Time Schedule 49 Cost Distribution Amount | 92,497 | 40,104 | 42,440 | 66 |
| 67 | Real Time Virtual Energy Amount | - | - | - | 67 |
| | **Real Time Subtotal** | $ 4,484,544 | $ 3,097,447 | $ 4,336,741 | |
| | **Grand Total** | $ 150,729 | $ (1,549,940) | $ (6,442,270) | |

**CERTIFICATE OF SERVICE**

The undersigned hereby certifies that a copy of the foregoing was served this 16th day of June, 2025, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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

**AES INDIANA**
**Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended April 30, 2025**
**(In $000's except where otherwise stated)**

| | | Per Books For The Twelve Months Ended April 30, 2025 | | | |
|---|---|---|---|---|---|
| Line No. | Description | Total Electric For the Twelve Months Ended April 30, 2025 | MISO Attachment GG | Applicable to Jurisdictional Retail Customers | Line No. |
| 1 | Operating Revenues | $ 1,718,929 | $ 3,329 | $ 1,715,600 | 1 |
| 2 | Operating Expenses: | | | | 2 |
| 3 | Operation and Maintenance Expenses | $ 1,020,969 | $ 1,577 | $ 1,019,392 | 3 |
| 4 | Depreciation and Amortization | 328,874 | 368 | 328,506 | 4 |
| 5 | Taxes Other than Income Taxes: | 30,498 | 70 | 30,428 | 5 |
| 6 | Income Taxes: | 48,380 | 225 | 48,156 | 6 |
| 7 | Total Operating Expenses | $ 1,428,721 | $ 2,240 | $ 1,426,482 | 7 |
| 8 | Operating Income | $ 290,208 | $ 1,089 | $ 289,118 | 8 |

(d)(2) Test (In $000's)
Summary of Increase in Operating Expenses Applicable to Jurisdictional Retail Customers
For the Twelve Months Ended April 30, 2025

| | | Per Cause Nos. 45029/45911 | Per Books April 30, 2025 | Increase (Decrease) | |
|---|---|---|---|---|---|
| 9 | Operating Expenses Excluding Fuel Costs | $ 896,231 | $ 972,814 | $ 76,583 | 9 |
| 10 | Fuel Costs * | 507,240 | 453,668 | (53,572) | 10 |
| 11 | Total Operating Expenses ** | $ 1,403,471 | $ 1,426,482 | $ 23,011 | 11 |

(d)(3) Test (In $'s)

| | | | |
|---|---|---|---|
| 12 | Jurisdictional Retail Electric Operating Income (April 30, 2025) | $ 289,118,000 | 12 |
| 13 | Total Authorized Operating Income [(1)] | 280,069,000 | 13 |
| 14 | Excess/(Deficiency) | $ 9,049,000 | 14 |

(1 ) Calculated on Applicant's Exhibit 3, page 2.

* Per the order in Cause No. 45029, total fuel costs were $436,216. Per Order in Cause No. 45911, fuel costs were $508,117. New rates were effective 5/9/24, thus 11 months (June 2024 - April 2025) and 23 days (May 9 - May 31, 2024) of the amounts in Cause Nos. 45911 were used in this calculation.
** Per the Order in Cause No. 45029 30 Day URT replease filing, total operating expenses were $1,172,651. Per Order in Cause No. 45911, operating expenses were $1,406,664. New base rates were effective 5/9/2024, thus 11 months (June 2024 - April 2025) and 23 days (May 9 - May 31, 2024) of the amount in Cause Nos. 45911 were used in this calculation.

**AES INDIANA**
**Determination of Authorized Return**
**For the Twelve Months Ended April 2025**

| Line No. | | | | Line No. |
|---|---|---|---|---|
| 1 | Operating Income per Cause No. 45029, through May 8, 2024, $220,076,000 annually | | $4,810,000 | 1 |
| 2 | Operating Income per Cause No. 45911, beginning on May 9, 2024, $235,972,000 annually | | 231,137,000 | 2 |
| 3 | Effective for May 1 - May 8 2024 | | | 3 |
| 4 | Allowed Return on TDISC 7 Distribution Utility Plant per Cause No. 45264-TDSIC 7 | 27,095,863 | | 4 |
| 5 | Jurisdictional Portion | 100.00% | | 5 |
| 6 | Jurisdictional Total for Cause No. 45264-TDSIC 7 | 27,095,863 | | 6 |
| 7 | Proration for Cause No.45264-TDSIC 7 (2) | 8/365 | | 7 |
| 8 | Total for Cause No. 45264-TDSIC 7 | | 594,000 | 8 |
| 9 | Effective for May 1 - May 8 2024 | | | 9 |
| 10 | Allowed Return on TDISC 7 - Transmission Utility Plant per Cause No. 45264-TDSIC 7 | 5,454,442 | | 10 |
| 11 | Jurisdictional Portion | 100.00% | | 11 |
| 12 | Jurisdictional Total for Cause No. 45264-TDSIC 7 | 5,454,442 | | 12 |
| 13 | Proration for Cause No.45264-TDSIC 7 (2) | 8/365 | | 13 |
| 14 | Total for Cause No. 45264-TDSIC 7 | | 120,000 | 14 |
| 15 | Effective for May 1 - May 8 2024 | | | 15 |
| 16 | Allowed Return on CCT NAAQS-Other Utility Plant per Cause No. 42170-ECR 37 | 1,431,000 | | 16 |
| 17 | Jurisdictional Portion | 100.00% | | 17 |
| 18 | Jurisdictional Total for Cause No. 42170-ECR 37 | 1,431,000 | | 18 |
| 19 | Proration for Cause No. 42170-ECR 37 (2) | 8/365 | | 19 |
| 20 | Total for Cause No. 42170-ECR 37 | | 31,000 | 20 |
| 21 | Effective for May 1 - May 8 2024 | | | 21 |
| 22 | Allowed Return on Hardy Hills, PEC, Pike BESS Investment per Cause No. 42170-ECR 37 | 29,441,395 | | 22 |
| 23 | Jurisdictional Portion | 100.00% | | 23 |
| 24 | Jurisdictional Total for Cause No. 42170-ECR 37 | 29,441,395 | | 24 |
| 25 | Proration for Cause No. 42170-ECR 37 (2) | 8/365 | | 25 |
| 26 | Total for Cause No. 42170-ECR 37 | | 645,000 | 26 |
| 27 | Effective for May 9 2024 - April 2025 | | | 27 |
| 28 | Allowed Return on TDISC 7 Distribution Utility Plant per Cause No. 45264-TDSIC 7 Compliance Filing | 7,976,126 | | 28 |
| 29 | Jurisdictional Portion | 100.00% | | 29 |
| 30 | Jurisdictional Total for Cause No. 45264-TDSIC 7 | 7,976,126 | | 30 |
| 31 | Proration for Cause No.45264-TDSIC 7 (2) | 357/365 | | 31 |
| 32 | Total for Cause No. 45264-TDSIC 7 | | 7,801,000 | 32 |
| 33 | Effective for May 9 2024 - April 2025 | | | 33 |
| 34 | Allowed Return on TDISC 7 - Transmission Utility Plant per Cause No. 45264-TDSIC 7 Compliance Filing | 1,461,049 | | 34 |
| 35 | Jurisdictional Portion | 100.00% | | 35 |
| 36 | Jurisdictional Total for Cause No. 45264-TDSIC 7 | 1,461,049 | | 36 |
| 37 | Proration for Cause No.45264-TDSIC 7 (2) | 357/365 | | 37 |
| 38 | Total for Cause No. 45264-TDSIC 7 | | 1,429,000 | 38 |
| 39 | Effective for May 9 2024 - April 2025 | | | 39 |
| 40 | Allowed Return on CCT NAAQS-Other Utility Plant per Cause No. 42170-ECR 37 Compliance Filing | 0 | | 40 |
| 41 | Jurisdictional Portion | 100.00% | | 41 |
| 42 | Jurisdictional Total for Cause No. 42170-ECR 37 | 0 | | 42 |
| 43 | Proration for Cause No. 42170-ECR 37 (2) | 296/365 | | 43 |
| 44 | Total for Cause No. 42170-ECR 37 | | 0 | 44 |
| 45 | Subtotal Authorized Operating Income | | $246,567,000 | 45 |

(2) The Commission requires that, for purposes of computing the authorized net operating income for IC 8-1-2-42(d)(2) and IC 8-1-2-42(d)(3), the jurisdictional portion of the increased return shall be phased-in over the appropriate period of time that the Applicant's net operating income is affected by this earnings modification resulting from the Commission's approval of the applicable Cost Rider. The Riders are pro-rated based on the effective rate day of the Order.

**AES INDIANA**
**Determination of Authorized Return**
**For the Twelve Months Ended April 2025**

| Line No. | | | | Line No. |
|---|---|---|---|---|
| 1 | Subtotal of Authorized Operating Income from Attachment NHC- 3, Page 1 | | $246,567,000 | 1 |
| 2 | Effective for May 9 2024 - April 2025 | | | |
| 3 | Allowed Return on Hardy Hills, PEC, Pike BESS Invest.per Cause No. 42170-ECR 37 Compliance Filing | 29,535,638 | | |
| 4 | Jurisdictional Portion | 100.00% | | |
| 5 | Jurisdictional Total for Cause No. 42170-ECR 37 | 29,535,638 | | |
| 6 | Proration for Cause No. 42170-ECR 37 (2) | 296/365 | | |
| 7 | Total for Cause No. 42170-ECR 37 | | 23,952,000 | |
| 8 | Effective for May 9 2024 - April 2025 | | | 8 |
| 9 | Allowed Return on Hardy Hills, PEC, Pike BESS, HWP Invest.per Cause No. 42170-ECR 37 Compliance Filing | 57,144,776 | | 9 |
| 10 | Jurisdictional Portion | 100.00% | | 10 |
| 11 | Jurisdictional Total for Cause No. 42170-ECR 37 | 57,144,776 | | 11 |
| 12 | Proration for Cause No. 42170-ECR 37 (2) | 61/365 | | 12 |
| 13 | Total for Cause No. 42170-ECR 37 | | 9,550,000 | 13 |
| 14 | Subtotal Authorized Operating Income | | $280,069,000 | 14 |

(2) The Commission requires that, for purposes of computing the authorized net operating income for IC 8-1-2-42(d)(2) and IC 8-1-2-42(d)(3), the jurisdictional portion of the increased return shall be phased-in over the appropriate period of time that the Applicant's net operating income is affected by this earnings modification resulting from the Commission's approval of the applicable Cost Rider. The Riders are pro-rated based on the effective rate day of the Order.

## AES INDIANA
## Earnings Test Summary

| FAC No. | Reporting Period | Determined Return | Authorized Return | Differential |
|---|---|---|---|---|
| 148 | 4/30/2025 | $289,118,000 | $280,069,000 | $9,049,000 |
| 147 | 1/31/2025 | 268,344,000 | 275,602,000 | (7,258,000) |
| 146 | 10/31/2024 | 242,572,000 | 271,781,000 | (29,209,000) |
| 145 | 7/31/2024 | 229,151,000 | 265,192,000 | (36,041,000) |
| 144 | 4/30/2024 | 191,751,000 | 258,095,000 | (66,344,000) |
| 143 | 1/31/2024 | 195,008,000 | 250,995,000 | (55,987,000) |
| 142 | 10/31/2023 | 199,943,000 | 246,817,000 | (46,874,000) |
| 141 | 7/31/2023 | 191,269,000 | 242,594,000 | (51,325,000) |
| 140 | 4/30/2023 | 191,845,000 | 238,368,000 | (46,523,000) |
| 139 | 1/31/2023 | 196,482,000 | 234,714,000 | (38,232,000) |
| 138 | 10/31/2022 | 203,266,000 | 231,914,000 | (28,648,000) |
| 137 | 7/31/2022 | 215,542,000 | 230,102,000 | (14,560,000) |
| 136 | 4/30/2022 | 223,712,000 | 228,291,000 | (4,579,000) |
| 135 | 1/31/2022 | 227,360,000 | 226,529,000 | 831,000 |
| 134 | 10/31/2021 | 226,080,000 | 224,682,000 | 1,398,000 |
| 133 | 7/31/2021 | 219,585,000 | 223,889,000 | (4,304,000) |
| 132 | 4/30/2021 | 232,893,000 | 223,097,000 | 9,796,000 |
| 131 | 1/31/2021 | 227,171,000 | 222,310,000 | 4,861,000 |
| 130 | 10/31/2020 | 229,881,000 | 221,451,000 | 8,430,000 |
| 129 | 7/31/2020 | 242,467,000 | 221,368,000 | 21,099,000 |
| | | | | ($374,420,000) |