FILED
December 19, 2023
INDIANA UTILITY
REGULATORY COMMISSION

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 MARCH 2024 THROUGH MAY 2024, 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 NOS. 43485 AND 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	**CAUSE NO. 38703 FAC 142**

APPLICANT'S SUBMISSION OF DIRECT TESTIMONY OF NATALIE HERR COKLOW

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

IURC
PETITIONER'S
EXHIBIT NO. 1
2-13-24 [illegible]
DATE REPORTER

OFFICIAL
EXHIBITS

Respectfully submitted,

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ATTORNEYS FOR APPLICANT
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 19th day of December, 2023, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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D/B/A AES INDIANA

DMS 41138180v1

APPLICANT'S EXHIBIT 1
I.U.R.C. CAUSE NO. 38703-FAC 142

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 Manager 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 most 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 pending basic rates case, Cause No. 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 charge 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 witnesses 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:

- Attachment NHC-l is a copy of the Verified Application filed in this proceeding, including Schedules 1 through 7 thereto which reflect the proposed factor.
- Attachment NHC-1-A is the proposed tariff sheets revised to reflect the fuel cost adjustment requested herein.
- Attachment NHC-2 is a Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended October 31, 2023.
- Attachment NHC-3 is a Determination of Authorized Return for the Twelve Months Ended October 31, 2023.
- Attachment NHC-4 is an Earnings Test Summary.

Q10. Is the information set forth in Attachments NHC-l through NHC-4 and Attachment NHC-1-A 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 Attachments NHC-1 through Attachment NHC-4.

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 Attachment NHC-1 for the purpose of its proposed fuel cost factor for electric service?

A14. Attachment NHC-1 estimates fuel costs over the months of March 2024 through May 2024.

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 August 2023 through October 2023 were reconciled with the estimated fuel costs for the same period. These variances are shown for reference in the FAC factor calculated on Attachment NHC-1, Schedule 5 and the reconciliations are included in the proposed factor on Attachment NHC-1, 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 Witness Jackson, the applicable Purchased Power Daily Benchmarks are set forth in Attachment DJ-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 Witness Jackson, AES Indiana is seeking to recover $981,430 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks for August 2023 through October 2023. A summary of the purchased power volumes, costs, the total hourly purchased power costs above the applicable Purchased Power Daily Benchmarks for August 2023 through October 2023 and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment DJ-2 to Witness Jackson'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 August 2023 through October 2023 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 C and D. The amounts accounted for as fuel recovery, when received, 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 FAC period of August through October 2023 as shown on Attachment NHC-1, Schedule 5, Line 20. 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 Jackson'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 August 2023 through October 2023?

A20. Yes. As shown in Attachment NHC-l, Schedule 5 (Page 4 of 4), the estimated fuel cost for those months was $0.037612 per kWh and the actual cost for the same period averaged $0.037095 per kWh, which represents an overestimate of 1.39%.

Q21. Based on such costs, in your opinion, are Applicant's estimated average fuel costs for the months of March 2024 through May 2024, 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, and purchased power from renewable resources. Also included are the estimated credits to customers for the off-system sales margins related to the Lakefield Wind power purchase agreement ("PPA") as required per the Commission's

Order in Cause No. 43740, as well as any realized gains or losses for financial hedges (including any associated transactional costs) from natural gas or purchased power hedging per the Commission's Order in Cause No. 38703 FAC 133.

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

A22. On October 31, 2018, the Commission issued an order in Cause No. 45029 (the "2018 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 June 30, 2017. AES Indiana implemented these new base rates on a service rendered basis effective December 5, 2018. The 2018 Base Rate Order established an annual level of operating income of $220,076,000.

Q23. Please explain <u>Attachments NHC-2, NHC-3, and NHC-4</u>.

A23. <u>Attachment NHC-2</u> contains a comparison of AES Indiana's electric retail operating results per books for the twelve months ended October 31, 2023, with the electric operating results applicable to jurisdictional retail customers for the same period. <u>Attachment NHC-2</u> 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 October 31, 2023, was higher than the authorized net electric operating income during the same period. <u>Attachment NHC-3</u> calculates AES Indiana's authorized return. That total authorized return was $246,817,000. In accordance with 170 IAC 4-6-21 and the Commission's Orders in Cause Nos. 42170 and 45264, AES Indiana added the return on its Qualified Pollution Control Property ("QPCP") and renewable projects of $5,194,000 and the return on its Transmission, Distribution and Storage System Improvement Charge Property ("TDSIC") of $21,547,000 (for a total of $26,741,000) to its authorized net operating income of $220,076,000. Attachment NHC-4 reflects the earnings bank total for the relevant period and calculates the differential between the determined return and the authorized return.

Q24. Based on the calculation on Attachment NHC-2, has AES Indiana passed "operating expense" test of I.C. § 8-1-2-42(d)(2)?

A24. 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.

Q25. 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?

A25. Yes. The sum of AES Indiana's differentials for the relevant period is less than zero as shown on Attachment NHC-4. In addition, Applicant's actual return was less than its authorized return for the twelve months ended October 31, 2023. The Company's actual return applicable to jurisdictional retail customers for the twelve months ended October 31, 2023, was $199,943,000, while the authorized net electric operating income during the same period was $246,817,000 and 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.

Q26. Were there any revenue and/or expenses eliminated or excluded from total electric operating income for the twelve months ended October 31, 2023, in the preparation of Applicant's Attachment NHC-2?

A26. No. AES Indiana did not eliminate or exclude any revenue and/or expenses from the total electric income for the twelve months ended October 31, 2023.

Q27. What was the source of the data contained in Attachment NHC-2?

A27. All the accounting figures and other financial data contained in Attachment NHC-2 were derived from AES Indiana's accounting records.

Q28. Is AES Indiana including FAC 133 S1 settlement costs in this FAC filing?

A28. Yes. AES Indiana has included costs of $2,564,810, as approved in the Settlement Agreement in FAC 133 S1 (Attachment NHC-1, Schedule 1, Lines No. 33, Column D). The Commission approved recovery of costs totaling $20,518,476 to be recovered over twenty-four months ($2,564,810 per FAC filing) beginning with the first FAC filing following the issuance of the Order, which was FAC 139.

Q29. What is the Applicant's estimated average cost of fuel for March 2024 through May 2024 as included in the proposed factor?

A29. The Applicant's estimated average cost of fuel for the months of March 2024 through May 2024, after taking into consideration the reconciliation of its estimated and actual fuel costs, and the inclusion of the FAC 133 S1 item, is estimated to be $0.036124 per kWh as shown on Attachment NHC-1, Schedule 1, Page 1 of 1, line 36. This represents an increase of $0.003186 per kWh from the base cost of fuel approved in the 2018 Base Rate Order of $0.032938 per kWh.

Q30. What effect will the proposed factor have on a residential customer using 1,000 kWh per month?

A30. In relation to the FAC factor currently in effect, the proposed factor will result in a decrease of $0.17 or 0.15% for a residential customer using 1,000 kWh per month.

Q31. 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?

A31. The Applicant seeks to make the fuel cost factor shown in <u>Attachment NHC-1</u>, Schedule 1, line 38 effective for all bills rendered for electric services beginning with the first billing cycles for the March 2024 billing month (Regular Billing District 41 and Special Billing District 01, which begins February 29, 2024). 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 <u>Attachment NHC-1-A</u>, attached hereto and made a part hereof.

Q32. Does that conclude your prefiled direct testimony?

A32. Yes.

VERIFICATION

I, Natalie Herr Coklow, Manager 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 19th day of December 2023.

Natalie Herr Coklow

Natalie Herr Coklow

FILED
December 19, 2023
INDIANA UTILITY
REGULATORY COMMISSION

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 MARCH 2024 THROUGH MAY 2024, 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 NOS. 43485 AND 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 142**

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 March 2024 through May 2024.

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 period of March 2024 through May 2024. The Company's filing also reflects a true-up of fuel-related MISO costs and revenues for the period of August 2023 through October 2023. As discussed further in the Company's testimony, the Company is including costs pursuant to the Settlement Agreement approved in Cause No. 38703 FAC 133S1. 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 Applicant did not earn more than the authorized level for the twelve months ending October 31, 2023; 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 David Jackson, Applicant continues to follow the guidelines and procedures established in Cause No. 43414. The Purchased Power Daily Benchmarks for August 2023 through October 2023 are set forth in Attachment DJ-1.

6. Applying the Purchased Power Daily Benchmarks set forth above to individual power purchase transactions included in this proceeding shows $981,676 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in August 2023 through October 2023, of which $246 is not recoverable. Applicant is therefore requesting recovery of $981,430 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 August 2023 through October 2023 and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment DJ-2.

7. Consistent with the Commission's Orders in Cause Nos. 43485 and 43740, Applicant continues to apply ratemaking treatment to recover the purchased power costs incurred under the Hoosier Wind Park and Lakefield Wind Park purchase power agreements.

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 months of March 2024 through May 2024, after taking into consideration its estimated and actual fuel costs for the months of August 2023 through October 2023, is estimated to be $0.036124 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 $0.003186. This factor would represent an increase from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of March 2024 through May 2024.

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:

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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**
January 23, 2024	OUCC/Intervenors File Case-in-Chief
January 31, 2024	Petitioner's Rebuttal Testimony
Week of February 12, 2024	Hearing
February 28, 2024	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 March 2024 (Regular Billing District 41 and Special Billing District 01), which begins February 29, 2024. 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 APPLICANT

Verification

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

Dated this 19th day of December, 2023.

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:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.032938$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of ~~December~~ March ~~2023~~ 2024 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.

Indianapolis Power & Light Company
d/b/a AES Indiana
One Monument Circle, Indianapolis, Indiana

I.U.R.C. No. E-18

~~22nd~~ 23rd Revised No. 158
Superseding
~~21st~~ 22nd Revised No. 158

STANDARD CONTRACT RIDER NO. 6 (Continued)

B. The Adjustment Factor as computed above shall be further modified to allow the recovery of Utility Receipts taxes and other similar 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 ~~May~~ August 2023 through ~~July~~ October 2023.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~December~~ March ~~2023~~ 2024 (Regular Billing District 41 and Special Billing Route 01) will be $~~0.003364~~0.003186 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:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.032938$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of March 2024 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 Utility Receipts taxes and other similar 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 August 2023 through October 2023.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for March 2024 (Regular Billing District 41 and Special Billing Route 01) will be $0.003186 per KWH.

Cause No. 38703-FAC142

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AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with March 2024 Based on the Estimated
Three Months Average of March, April, and May 2024

Line No.	Description	(A) Estimated Month of: March	(B) Estimated Month of: April	(C) Estimated Month of: May	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	514,768	533,770	297,209	1,345,747	448,582	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	933,857	520,842	867,618	2,322,317	774,106	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	72,147	67,627	61,804	201,579	67,193	6
7	Non-Wind PPA Market Purchases	14,802	66,582	34,475	115,859	38,620	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	9,550	13,088	14,264	36,902	12,301	9
	LESS:						
10	Energy Losses and Company Use	48,367	43,204	46,525	138,096	46,032	10
11	Inter-System Sales through MISO	454,477	227,683	226,260	908,420	302,807	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,042,279	931,022	1,002,586	2,975,887	991,963	14
	Fuel Cost ($)						
15	Coal and Oil Generation	16,505,006	16,187,866	8,890,221	41,583,092	13,861,031	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	24,665,944	16,248,561	24,077,898	64,992,403	21,664,134	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	4,896,627	4,933,389	4,264,349	14,094,365	4,698,122	20
21	Non-Wind PPA Market Purchases	509,685	1,985,071	1,316,274	3,811,030	1,270,343	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	1,406,035	1,255,949	1,352,488	4,014,472	1,338,157	23
24	Purchased Power other than MISO	1,507,140	2,100,370	2,315,420	5,922,930	1,974,310	24
	Less:						
25	Inter-System Sales through MISO	11,872,239	6,424,505	5,622,033	23,918,777	7,972,926	25
26	Inter-System Sales other than MISO	-	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	-	-	-	27
28	Transmission Losses	392,073	378,296	358,732	1,129,101	376,367	28
29	Lakefield PPA Adjustment	168,044	92,021	132,999	393,064	131,021	29
30	**Total Fuel Cost (F)**	$ 37,058,081	$ 35,816,385	$ 36,102,886	$ 108,977,352	$ 36,325,783	30
31	**F ÷ S (Line 31 ÷ Line 14) (Mills/kWh)**					36.620	31

Line No.	Description	Months to be Reconciled: August	September	October	Total		Line No.
32	Fuel Cost Variance	$ (3,846,908)	$ 924,470	$ (1,117,776)	$ (4,040,214)		32
33	FAC 133 S1 Settlement Costs to Recovered over 24 Months(1)				2,564,810		33
34	Total Fuel Cost Variance and Adjustments Included in this Filing					$ (1,475,404)	34

Line No.	Description			Line No.
	(Mills/kWh)			
35	Variance Charge (Line 34 Total divided by estimated Indiana jurisdictional sales of	2,975,887 kWh (000's)	(0.496)	35
36	Adjusted Fuel Cost Charge (Line 31 + Line 35)		36.124	36
37	Less: Base Cost of Fuel Included in Rates		32.938	37
38	Fuel Cost Charge		3.186	38

(1) Per the Order in Cause No. 38703 FAC 133 S1, $20,518,476 of previously deferred costs are to be collected over 24 months beginning with the first FAC filing after issuance of a final Order which is FAC 139 with rates begininning in June 2023. In addition, the approved settlement agreement included a one-time credit of $6,800,000 to offset costs in the first FAC filing after the issuance of a final Order.

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Applicant's Attachment NHC-1
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AES INDIANA
Determination of Net Energy Cost of Purchased Power
For the Estimated Months of March, April, and May 2024

Line No	Supplier	kWh Purchased (000's)	Energy *	Line No
		(A)	(B)	
	March			
	Purchases through MISO:			
1	Wind Purchase Power Agreement Purchases	72,147	$ 4,896,627	1
2	Non-Wind PPA Market Purchases	14,802	509,685	2
3	Other	-	-	3
4	MISO Components of Cost of Fuel	-	1,406,035	4
5	Purchased Power other than MISO	9,550	1,507,140	5
6	Total	96,499	$ 8,319,487	6
	April			
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	67,627	$ 4,933,389	7
8	Non-Wind PPA Market Purchases	66,582	1,985,071	8
9	Other	-	-	9
10	MISO Components of Cost of Fuel	-	1,255,949	10
11	Purchased Power other than MISO	13,088	2,100,370	11
12	Total	147,297	$ 10,274,779	12
	May			
	Purchases through MISO:			
13	Wind Purchase Power Agreement Purchases	61,804	$ 4,264,349	13
14	Non-Wind PPA Market Purchases	34,475	1,316,274	14
15	Other	-	-	15
16	MISO Components of Cost of Fuel	-	1,352,488	16
17	Purchased Power other than MISO	14,264	2,315,420	17
18	Total	110,543	$ 9,248,531	18
19	Total Net Energy Cost of Purchased Power	354,340	$ 27,842,797	19

* Demand Charges have not been estimated.

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Applicant's Attachment NHC-1
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AES INDIANA
Determination of Fuel Costs Recovered Through Inter-System and Non-Jurisdictional Retail Sales by Month
For the Estimated Months of March, April, and May 2024

Line No.	Purchaser	kWh Sold (000's)	Fuel Cost *	Line No.
		(A)	(B)	
	March			
1	Inter-System Sales through MISO	454,477	$ 11,872,239	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	454,477	$ 11,872,239	4
	April			
5	Inter-System Sales through MISO	227,683	$ 6,424,505	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	227,683	$ 6,424,505	8
	May			
9	Inter-System Sales through MISO	226,260	$ 5,622,033	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	226,260	$ 5,622,033	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	908,420	$ 23,918,777	13

* Demand Charges have not been estimated.

Cause No. 38703-FAC142

Applicant's Attachment NHC-1
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AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for August 2023

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 36.687 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-FAC138/FAC139 (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	467,218	$ 15,389,226	$ 17,140,828	$ 1,751,602	$ 1,334,084				1
2	Total Commercial	158,635	5,225,120	5,819,842	594,722	454,405				2
3	Total Industrial	573,761	18,898,540	21,049,570	2,151,030	1,623,955				3
4	Total Electric Vehicle Public Charging Stations	5	165	183	18	11				4
5	Total Lighting	3,923	129,216	143,923	14,707	14,872				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,203,542	$ 39,642,267	$ 44,154,346	$ 4,512,079	$ 3,427,327	$ (4,931,660)	$ 8,358,987	$ (3,846,908)	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,203,542								10

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 139 ($14,794,981), or ($4,931,660) per month.

Cause No. 38703-FAC142

Applicant's Attachment NHC-1
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AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for September 2023

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 37.415 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-FAC139/FAC140 (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	431,463	$ 14,211,528	$ 16,143,188	$ 1,931,660	$ (1,329,505)				1
2	Total Commercial	155,565	5,124,000	5,820,464	696,464	(480,891)				2
3	Total Industrial	550,914	18,146,005	20,612,447	2,466,442	(1,705,015)				3
4	Total Electric Vehicle Public Charging Stations	7	231	262	31	(22)				4
5	Total Lighting	4,287	141,205	160,398	19,193	72,586				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,142,236	$ 37,622,969	$ 42,736,759	$ 5,113,790	$ (3,442,846)	$ (7,632,167)	$ 4,189,320	$ 924,470	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,142,236								10

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 140 ($22,896,500), or ($7,632,167) per month.

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AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for October 2023

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 37.279 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-FAC139/FAC140 (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	291,107	$ 9,588,482	$ 10,852,178	$ 1,263,696	$ (903,719)				1
2	Total Commercial	118,174	3,892,415	4,405,409	512,994	(366,389)				2
3	Total Industrial	460,353	15,163,107	17,161,499	1,998,392	(1,428,627)				3
4	Total Electric Vehicle Public Charging Stations	5	165	186	21	(16)				4
5	Total Lighting	5,053	166,436	188,371	21,935	(18,602)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	874,692	$ 28,810,605	$ 32,607,643	$ 3,797,038	$ (2,717,353)	$ (7,632,167)	$ 4,914,814	$ (1,117,776)	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	874,692								10

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 140 ($22,896,500), or ($7,632,167) per month.

Cause No. 38703-FAC142

Applicant's Attachment NHC-1
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AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation August 2023

Line No.	Description	August Actual	August Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	384,213	553,906	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	13	-	4
5	Gas Generation	642,488	883,452	5
	Purchases through MISO:			
6	Wind Purchase Power Agreement Purchases	42,398	37,904	6
7	Non-Wind PPA Market Purchases	166,279	44,823	7
8	Other	684	-	8
9	Purchased Power other than MISO	14,423	24,138	9
	LESS:			
10	Energy Losses and Company Use	58,893	59,413	10
11	Inter-System Sales through MISO	19,055	204,495	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,172,550	1,280,315	14
	Fuel Cost			
15	Coal and Oil Generation	$ 12,409,643	$ 18,326,678	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	3,060	-	18
19	Gas Generation	18,051,955	28,655,600	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO:			
21	Wind Purchase Power Agreement Purchases	3,823,623	3,782,908	21
22	Non-Wind PPA Market Purchases	5,813,428	1,704,143	22
23	Other	27,073	-	23
24	MISO Components of Cost of Fuel	1,019,194	2,063,868	24
25	Purchased Power other than MISO	2,402,566	2,925,300	25
	LESS:			
26	Inter-System Sales through MISO	453,095	6,075,594	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	73,811	547,753	29
30	Lakefield PPA Adjustment	5,851	396,120	30
31	Purchased Power in Excess	246	-	31
32	Total Fuel Costs (F)	$ 43,017,539	$ 50,439,030	32
33	F / S (Mills/kWh)	36.687	39.396	33
	Weighted Average Deviation	7.38%		

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AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation September 2023

Line No.	Description	September Actual	September Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	340,135	223,489	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	9	-	4
5	Gas Generation	559,113	861,349	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	43,775	53,074	6
7	Non-Wind PPA Market Purchases	86,565	78,271	7
8	Other	715	-	8
9	Purchased Power other than MISO	13,861	28,418	9
	LESS:			
10	Energy Losses and Company Use	49,532	48,651	10
11	Inter-System Sales through MISO	19,620	147,554	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	975,021	1,048,396	14
	Fuel Cost			
15	Coal and Oil Generation	$ 12,575,922	$ 7,938,512	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	1,637	-	18
19	Gas Generation	15,527,975	21,476,364	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	4,019,321	5,169,429	21
22	Non-Wind PPA Market Purchases	2,593,770	2,529,789	22
23	Other	28,607	-	23
24	MISO Components of Cost of Fuel	10,984	2,366,230	24
25	Purchased Power other than MISO	2,291,437	2,956,090	25
	LESS:			
26	Inter-System Sales through MISO	473,017	3,246,300	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	83,476	332,143	29
30	Lakefield PPA Adjustment	12,741	483,640	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 36,480,419	$ 38,374,330	32
33	F / S (Mills/kWh)	37.415	36.603	33
	Weighted Average Deviation	-2.17%		

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AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation October 2023

Line No.	Description	October Actual	October Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	396,970	271,588	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	10	-	4
5	Gas Generation	754,540	868,905	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	53,874	65,530	6
7	Non-Wind PPA Market Purchases	25,038	34,744	7
8	Other	586	-	8
9	Purchased Power other than MISO	10,550	26,355	9
	LESS:			
10	Energy Losses and Company Use	45,603	45,607	10
11	Inter-System Sales through MISO	289,308	238,722	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	906,657	982,794	14
	Fuel Cost			
15	Coal and Oil Generation	$ 13,763,858	$ 9,354,209	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	1,820	-	18
19	Gas Generation	17,640,012	20,006,166	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	6,450,674	6,493,206	21
22	Non-Wind PPA Market Purchases	810,042	1,319,574	22
23	Other	24,004	-	23
24	MISO Components of Cost of Fuel	1,016,280	2,218,166	24
25	Purchased Power other than MISO	1,756,176	2,493,180	25
	LESS:			
26	Inter-System Sales through MISO	7,215,220	5,510,678	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	267,165	326,691	29
30	Lakefield PPA Adjustment	181,352	308,855	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 33,799,129	$ 35,738,276	32
33	F / S (Mills/kWh)	37.279	36.364	33
	Weighted Average Deviation	-2.45%		

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AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
August, September, and October 2023

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	1,121,318	1,048,983	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	32	-	4
5	Gas Generation	1,956,141	2,613,707	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	140,047	156,508	6
7	Non-Wind PPA Market Purchases	277,882	157,838	7
8	Other	1,985	-	8
9	Purchased Power other than MISO	38,834	78,911	9
	LESS:			
10	Energy Losses and Company Use	154,028	153,670	10
11	Inter-System Sales through MISO	327,983	590,771	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	3,054,228	3,311,505	14
	Fuel Cost			
15	Coal and Oil Generation	$ 38,749,423	$ 35,619,399	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	6,517	-	18
19	Gas Generation	51,219,942	70,138,130	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	14,293,618	15,445,543	21
22	Non-Wind PPA Market Purchases	9,217,240	5,553,506	22
23	Other	79,684	-	23
24	MISO Components of Cost of Fuel	2,046,458	6,648,265	24
25	Purchased Power other than MISO	6,450,179	8,374,570	25
	LESS:			
26	Inter-System Sales through MISO	8,141,332	14,832,573	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	424,452	1,206,588	29
30	Lakefield PPA Adjustment	199,944	1,188,615	30
31	Purchased Power in Excess	246	-	31
32	Total Fuel Costs (F)	$ 113,297,087	$ 124,551,636	32
33	F / S (Mills/kWh)	37.095	37.612	33
	Weighted Average Deviation	1.39%		

Cause No. 38703-FAC142

Applicant's Attachment NHC-1
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AES INDIANA
Determination of MISO Components of Fuel Cost
August, September, and October 2023

Line No.	Energy Market FAC Adjustment Components	Total August **(A)**	Total September **(B)**	Total October **(C)**	Line No.
1	Delta LMP[1]	$ 2,101,127	$ 1,473,785	$ 1,511,277	1
2	FTR (Revenue) / Expenses	(696,469)	(1,292,257)	(500,981)	2
3	RT Marg. Loss Surplus Credit	(515,092)	(271,459)	(145,233)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	(5,751)	9,862	14,770	5
5a	RSG 1st Pass Charges	44,905	15,744	17,786	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	(33,836)	(1,908)	(13,886)	6
7	Ancillary Services Revenue	(31,748)	(14,567)	(24,245)	7
8	Ancillary Services Costs	143,694	89,302	123,814	8
9	Ancillary Services Incentive to Follow Dispatch[2]	6,986	2,685	23,993	9
10	Ramp Capability[3]	5,378	(203)	8,985	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 24)	$ 1,019,194	$ 10,984	$ 1,016,280	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

AES INDIANA
MISO Charges by Month by Charge Type

Line No.	Charge Type	Aug-23 Invoice Total	Sep-23 Invoice Total	Oct-23 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$ 182,528	$ 144,318	$ 237,593	1
2	Day Ahead Regulation Amount	-	-	(840)	2
3	Day Ahead Spinning Reserve Amount	(1,100)	(3,813)	(5,606)	3
4	Day-Ahead Short-Term Reserve Amount	(12,414)	(4,374)	(2,548)	4
5	Day Ahead Supplemental Reserve Amount	-	-	-	5
6	Day Ahead Asset Energy Amount	4,198,454	2,329,731	(6,605,722)	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	(818)	(11,456)	(6,835)	14
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	25,498	22,299	18,765	15
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	(25,352)	(3,340)	(1,552)	16
17	Day Ahead Schedule 24 Allocation Amount	28,881	24,564	30,495	17
18	Day Ahead Virtual Energy Amount	-	-	-	18
	Day Ahead Subtotal	$ 4,395,677	$ 2,497,929	$ (6,336,250)	
19	Financial Transmission Rights Market Administration Amount	4,084	3,034	3,257	19
20	Auction Revenue Rights Transaction Amount	(520,030)	(474,311)	(474,311)	20
21	Financial Transmission Rights Annual Transaction Amount	330,658	281,877	281,877	21
22	Auction Revenue Rights Infeasible Uplift Amount	7,664	11,866	11,866	22
23	Auction Revenue Rights Stage 2 Distribution Amount	(240,721)	(221,810)	(221,810)	23
24	Financial Transmission Rights Full Funding Guarantee Amount	-	(110,398)	(4,081)	24
25	Financial Transmission Guarantee Uplift Amount	-	31,773	6,592	25
26	Financial Transmission Rights Hourly Allocation Amount	(271,155)	(757,589)	(99,038)	26
27	Financial Transmission Rights Monthly Allocation Amount	(2,885)	(53,665)	(2,076)	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	$ (692,385)	$ (1,289,223)	$ (497,724)	
31	Real Time Market Administration Amount	$ 19,099	$ 12,588	$ 23,887	31
32	Contingency Reserve Deployment Failure Charge Amount	-	-	-	32
33	Excessive Energy Amount	(5,234)	(3,543)	(89,949)	33
34	Real Time Excessive Deficient Energy Deployment Charge Amount	6,091	1,802	21,061	34
35	Net Regulation Adjustment Amount	-	-	-	35
36	Non-Excessive Energy Amount	1,153,242	1,736,327	299,801	36
37	Real Time Regulation Amount	(130)	(816)	(2,425)	37
38	Regulation Cost Distribution Amount	34,103	37,896	42,452	38
39	Real Time Spinning Reserve Amount	(3,625)	(4,874)	(9,830)	39
40	Spinning Reserve Cost Distribution Amount	34,401	33,574	48,504	40
41	Real Time Short-Term Reserve Amount	(14,104)	(690)	(2,995)	41
42	Real-Time Short-Term Reserve Deployment Failure Charge Amount	-	-	-	42
43	Short-Term Reserve Cost Distribution Amount	65,298	11,047	24,563	43
44	Real Time Supplemental Reserve Amount	(376)	-	-	44
45	Supplemental Reserve Cost Distribution Amount	9,892	6,785	8,296	45
46	Real Time Asset Energy Amount	2,152,220	(487,622)	(81,932)	46
47	Real Time Demand Response Allocation Uplift Charge	1,561	959	3,041	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	(515,092)	(271,459)	(145,233)	52
53	Real Time Miscellaneous Amount	(2,180)	(212,170)	22,983	53
54	Real Time MVP Distribution Amount	(4,773)	(9,781)	(8,926)	54
55	Real Time Non-Asset Energy Amount	-	-	-	55
56	Real Time Net Inadvertent Distribution Amount	(33,836)	(1,908)	(13,886)	56
57	Real Time Price Volatility Make Whole Payment	(252,962)	(165,046)	(196,806)	57
58	Real Time Resource Adequacy Auction Amount	149,079	(12,075)	(27,029)	58
59	Real Time Ramp Capability Amount	(4,400)	(1,983)	(5,032)	59
60	Real Time Revenue Neutrality Uplift Amount	507,784	473,014	450,574	60
61	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	63,976	16,855	28,460	61
62	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	(5,901)	(9,097)	(2,551)	62
63	Real-Time Storage as Transmission Only Asset Amount	-	-	-	63
64	Real Time Schedule 24 Allocation Amount	3,071	2,143	3,066	64
65	Real Time Schedule 24 Distribution Amount	(64,670)	(55,929)	(63,867)	65
66	Real Time Schedule 49 Cost Distribution Amount	54,776	58,688	55,537	66
67	Real Time Virtual Energy Amount	-	-	-	67
	Real Time Subtotal	$ 3,347,310	$ 1,154,685	$ 381,764	
	Grand Total	$ 7,050,602	$ 2,363,391	$ (6,452,210)	

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 1500 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 19th day of December, 2023.

Jeffrey M. Peabody

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ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

AES INDIANA
Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended October 31, 2023
(In $000's except where otherwise stated)

Line No.	Description	Per Books For The Twelve Months Ended October 31, 2023: Total Electric For the Twelve Months Ended October 31, 2023	MISO Attachment GG	Applicable to Jurisdictional Retail Customers	Line No.
1	Operating Revenues	$ 1,747,398	$ 2,009	$ 1,745,389	1
2	Operating Expenses:				2
3	Operation and Maintenance Expenses	$ 1,214,249	$ 670	$ 1,213,579	3
4	Depreciation and Amortization	281,370	384	280,986	4
5	Taxes Other than Income Taxes:	26,145	53	26,092	5
6	Income Taxes:	24,947	158	24,789	6
7	Total Operating Expenses	$ 1,546,711	$ 1,265	$ 1,545,445	7
8	Operating Income	$ 200,687	$ 744	$ 199,943	8

(d)(2) Test (In $000's)
Summary of Increase in Operating Expenses Applicable to Jurisdictional Retail Customers
For the Twelve Months Ended October 31, 2023

Line No.	Description	Per Cause Nos. 45029	Per Books October 31, 2023	Increase (Decrease)	Line No.
9	Operating Expenses Excluding Fuel Costs	$ 736,436	$ 832,642	$ 96,206	9
10	Fuel Costs *	436,216	712,803	276,587	10
11	Total Operating Expenses **	$ 1,172,652	$ 1,545,445	$ 372,793	11

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

Line No.	Description	Amount	Line No.
12	Jurisdictional Retail Electric Operating Income (October 31, 2023)	$ 199,943,000	12
13	Total Authorized Operating Income (1)	246,817,000	13
14	Excess/(Deficiency)	$ (46,874,000)	14

(1) Calculated on Applicant's Exhibit 3.

* Per Cause No. 45029.
** Per Cause No. 45029, updated for 30 day URT repeal filing.

Cause No. 38703-FAC142 **Applicant's Attachment NHC-3**

AES INDIANA
Determination of Authorized Return
For the Twelve Months Ended October 2023

Line No.				Line No.
1	Operating Income per Cause No. 45029		$220,076,000	1
2	Effective for November 2022 - February 2023			2
3	Allowed Return on CCT NAAQS-Other Utility Plant per Cause No. 42170-ECR35	1,458,112		3
4	Jurisdictional Portion	100.00%		4
5	Jurisdictional Total for Cause No. 42170-ECR35	1,458,112		5
6	Proration for Cause No. 42170-ECR35 (2)	120/365		6
7	Total for Cause No. 42170-ECR35		479,000	7
8	Effective for November 2022 - October 2023			8
9	Allowed Return on TDISC-5 Distribution Utility Plant per Cause No. 45264-TDSIC-5	17,761,951		9
10	Jurisdictional Portion	100.00%		10
11	Jurisdictional Total for Cause No. 45264-TDSIC-5	17,761,951		11
12	Proration for Cause No.45264-TDSIC-5 (2)	365/365		12
13	Total for Cause No. 45264-TDSIC-5		17,762,000	13
14	Effective for November 2022 - October 2023			14
15	Allowed Return on TDISC-5 - Transmission Utility Plant per Cause No. 45264-TDSIC-5	3,784,848		15
16	Jurisdictional Portion	100.00%		16
17	Jurisdictional Total for Cause No. 45264-TDSIC-5	3,784,848		17
18	Proration for Cause No.45264-TDSIC-5 (2)	365/365		18
19	Total for Cause No. 45264-TDSIC-5		3,785,000	19
19	Effective for March 2023 - November 2023			19
20	Allowed Return on CCT NAAQS-Other Utility Plant per Cause No. 42170-ECR36	1,459,197		20
21	Jurisdictional Portion	100.00%		21
22	Jurisdictional Total for Cause No. 42170-ECR36	1,459,197		22
23	Proration for Cause No. 42170-ECR36 (2)	245/365		23
24	Total for Cause No. 42170-ECR36		979,000	24
25	Effective for March 2023 - November 2023			25
26	Allowed Return on Hardy Hills Investment per Cause No. 42170-ECR36	5,565,867		26
27	Jurisdictional Portion	100.00%		27
28	Jurisdictional Total for Cause No. 42170-ECR36	5,565,867		28
29	Proration for Cause No. 42170-ECR36 (2)	245/365		29
30	Total for Cause No. 42170-ECR36		3,736,000	30
31	Total Authorized Operating Income		$246,817,000	31

(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 applicalbe 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
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
128	4/30/2020	236,917,000	221,285,000	15,632,000
127	1/31/2020	234,075,000	221,201,000	12,874,000
126	10/31/2019	230,875,000	218,710,000	12,165,000
125	7/31/2019	229,431,000	206,716,000	22,715,000
124	4/30/2019	217,179,000	194,654,170	22,524,830
123	1/31/2019	212,078,000	182,107,612	29,970,388
				($72,748,782)