VERIFIED DIRECT TESTIMONY

OF

KIMBERLY ALIFF

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

D/B/A AES INDIANA

Cause No. 46258

SPONSORING AES INDIANA ATTACHMENTS KA-1 AND KA-2

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ON BEHALF OF AES INDIANA

1. INTRODUCTION

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

A1. My name is Kimberly Aliff. I am employed by Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL", or "the Company"). My business address is One Monument Circle, Indianapolis, IN 46204.

Q2. What is your position with AES Indiana?

A2. I am a Revenue Requirements Manager in Regulatory Affairs.

Q3. On whose behalf are you submitting this direct testimony?

A3. I am submitting this testimony on behalf of AES Indiana.

Q4. Please describe your duties as Revenue Requirements Manager.

A4. As a Revenue Requirements Manager, I provide financial, technical, and regulatory analysis and I manage or am involved with filings to support various regulatory projects and rate recovery mechanisms. Additionally, I am involved with the planning, development, and analysis of Demand Side Management ("DSM") Programs, as well as tracking and reporting program results. I am a member of AES Indiana's DSM Oversight Board ("OSB").

Q5. Please summarize your education and professional qualifications.

A5. I have a Bachelor of Science Degree in Accounting and Computer Information Systems from Indiana University and a Master of Business Administration from the University of

Indianapolis. I have also attended various regulated utility training courses such as Edison Electric Institute ("EEI") Utilities Accounting Courses and EEI Electric Rates Courses as well as educational courses related to planning, implementation, and evaluation of DSM programs.

Q6. Please summarize your prior work experience.

A6. I have been an employee of the Company since April 25, 2005. During my tenure with the Company, I worked in various accounting staff roles until 2010, when I transferred to Regulatory Affairs as a Research Analyst and later as a Senior Regulatory Analyst and most recently my current position of Revenue Requirements Manager.

Q7. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission")?

A7. Yes, I have previously testified before the Commission regarding accounting and ratemaking treatment for the Company's Electric Vehicle Sharing Program in Cause No. 44478, and in proceedings involving the Company's requests approval of a portfolio of Electric Vehicle offerings in Cause Nos. 45509 and 45843. I have also testified regarding cost recovery and cost allocation for AES Indiana's DSM Plans in Cause Nos. 44328, 44497, 44792, 44945, 45370, 45898 and 46081. I have been a witness in the Company's prior Demand Side Management Adjustment (Cause No. 43623-DSM-XX) proceedings beginning with DSM-10 and in the Company's RTO Adjustment proceedings (Cause No. 44808 RTO-4 and RTO-5). I also provided testimony in AES Indiana's previous electric rate case in Cause No. 45911. I have also testified regarding accounting and ratemaking treatment for the Crossvine Project in Cause No. 46113.

Q8. What is the purpose of your testimony in this proceeding?

A8. My testimony presents AES Indiana's overall forecasted revenue requirement in this proceeding[1] and explains the Company's proposal to implement the rates approved by the Commission in this proceeding through the Phase-in Rate Adjustment ("PRA"). I discuss the proposed alternative recovery and ratemaking treatment for Petersburg Repowering Project in the event the project is not complete by the end of the Test Year and the development of new lost revenue margin rates. I also support certain forecasted rate base, revenues, and operating expense balances and/or adjustments, including:

Rate Base

- The removal of Eagle Valley forced outage costs and non-jurisdictional Midcontinent Independent System Operator ("MISO") Transmission Expansion Plan ("MTEP") projects from forecasted rate base.
- Regulatory assets included in forecasted rate base, including forecasted amortization expense associated with these regulatory assets.

Revenue

- Adjustments to forecasted electric operating revenue and miscellaneous electric revenue.

Operating Expenses

- The removal of forecasted MISO non-jurisdictional operating expenses related to MTEP projects and the forecasted MISO non-fuel costs.

[1] AES Indiana witness Peters discusses the process for developing the forecast.

- The continuation of the Major Storm Damage Restoration Reserve account and the Vegetation Management Reserve methodology established in Cause No. 45029.
- Forecasted amortization of AES Indiana's regulatory asset for MISO non-Fuel costs, deferred MISO expense amortization and the one-time Operations & Maintenance ("O&M") costs related to the ACE Project, and the removal of certain customer program costs from base rates.
- Ongoing amortization of unamortized rate case expense from Cause No. 45911.

I also discuss AES Indiana's proposal to continue existing standard contract riders, and proposed changes to these riders, as well as the addition of a new standard contract rider for property tax recovery.

Q9. Are you sponsoring or co-sponsoring any financial exhibits, schedules or attachments?

A9. Yes. I sponsor or co-sponsor the following financial exhibit schedules:

Revenue Requirement

1. AES Indiana Financial Exhibit AESI-REVREQ, Schedule REVREQ1 – Allowable Electric Operating Income Requirement.

Rate Base

2. AES Indiana Financial Exhibit AESI-RB, Schedule RB3 – Remove Eagle Valley Forced Outage Capital Costs.
3. AES Indiana Financial Exhibit AESI-RB, Schedule RB4 – Remove Non-Jurisdictional MISO MTEP Plant in Service.
4. AES Indiana Financial Exhibit AESI-RB, Schedule RB8 – Regulatory Assets Includable in Electric Rate Base.

Revenue Adjustments

5. AES Indiana Financial Exhibit AESI-OPER, Schedule REV5 – Summary of Electric Operating Revenue Adjustments Adding Back Adjusted Test Year Rider Revenues to Achieve Total Electric Retail Revenue.

6. AES Indiana Financial Exhibit AESI-OPER, Schedule REV8 – Summary of Miscellaneous Electric Revenue.

Operating Expenses

7. AES Indiana Financial Exhibit AESI-OPER, Schedule OM10 – Non-Jurisdictional MISO MTEP Operations and Maintenance Expenses.

8. AES Indiana Financial Exhibit AESI-OPER, Schedule OM11 – Storm Expenses.

9. AES Indiana Financial Exhibit AESI-OPER, Schedule OM13 – MISO Non-Fuel Costs.

10. AES Indiana Financial Exhibit AESI-OPER. Schedule OM14 – MISO Deferred Expense Amortization.

11. AES Indiana Financial Exhibit AESI-OPER. Schedule OM18 – Adjustment for ACE One-Time Costs Annualized Expense.

12. AES Indiana Financial Exhibit AESI-OPER Schedule OM22 – Remove Customer Program Costs.

Rates & Tariffs

13. AES Indiana witness AJB Attachments 1 & 2 AES Indiana's Proposed New Tariff (clean and redline):

    a. Certain changes to the text of existing riders: Standard Contract Rider No. 6 Fuel Cost Adjustment ("FAC"), Standard Contract Rider No. 24 Capacity ("CAP") Cost Recovery Adjustment, Standard Contract Rider No. 25 Off-System Sales ("OSS") Margin Adjustment, and Standard Contract Rider No. 26 Regional Transmission Organization ("RTO") Adjustment.

    b. New Standard Contract Rider No. 18 Property Taxes Adjustment ("PTA").

    c. New Standard Contract Rider No. 28 Phase-In Rate Adjustment Rider ("PRA").

I support the ongoing amortization of past rate case expense as authorized in Cause No. 45911 presented on AES Indiana Financial Exhibit AESI-OPER Schedule OM21 co-sponsored by AES Indiana witness Peters.

I also sponsor the following attachments:

- AES Indiana Attachment KA-1 – Summary of Regulatory Assets and Amortization.
- AES Indiana Attachment KA-2 – Lost Revenue Margin Rates.

Q10. Please discuss your role in presenting AES Indiana's proposed rates in this proceeding.

A10. My role is to present the Company's calculation of its forecasted revenue requirement for the Adjusted Test Year, which is calendar year 2026. To do that, I started with the forecast prepared by AES Indiana witness Peters, then incorporated adjustments as necessary to reflect certain Commission Orders, changes to rate base, regulatory assets, expenses, and revenues – with the goal being to present a reasonable, ongoing level of revenue requirement for the Company. I then provided the Adjusted Test Year revenue requirement calculations to AES Indiana witness Rimal for cost of service and rate design purposes. As discussed in more detail below, AES Indiana is proposing to implement base rates in two phases with the use of a phase-in rate adjustment (also referred to as the "PRA").

Q11. Did you submit any workpapers?

A11. Yes. AES Indiana is submitting workpapers in electronic format that support the basic rate case schedules. I am sponsoring the workpapers that support the schedules and attachments that I sponsor. I also sponsor AES Indiana Witness KA Confidential Workpapers 1-8 which support the calculation of the Revenue Requirement impact of including the Petersburg Repowering Project in the Environmental Compliance Cost Recovery Adjustment.

Q12. Were these exhibits, attachments, or workpapers, or portions thereof, that you are sponsoring or co-sponsoring prepared or assembled by you or under your direction and supervision?

A12. Yes.

Q13. For ease of reference, please summarize the key terms utilized in the Company's filing.

A13. Key terms utilized in the filing include the following.[2] First, the per books twelve months ended December 31, 2024 is the Historical Base Period. Second, the forecasted twelve months ending December 31, 2025, is the Linking Period. Next, the unadjusted forward-looking test year for twelve months ending December 31, 2026, is the Unadjusted Test Year. Finally, the adjusted forward-looking test year for the twelve months ending December 31, 2026, is the Adjusted Test Year.

2. REVENUE REQUIREMENT

Q14. Please explain AES Indiana Financial Exhibit AESI-REVREQ, Schedule REVREQ1 - Allowable Electric Operating Income Requirement.

A14. This schedule shows the calculation for the overall revenue increase for the Adjusted Test Year AES Indiana is proposing in this proceeding. First, the Rate of Return[3] was applied

[2] AES Indiana witness Peters, Q/A 13.
[3] Rate of return is supported by AES Indiana witnesses McKenzie and Illyes and is presented in AES Indiana Financial Exhibit AESI-CC, Schedule CC2.

to Adjusted Test Year rate base from AES Indiana Financial Exhibit AESI-RB, Schedule RB1[4] to determine the allowable electric operating income requirement.

The deficiency in electric operating income of $144.1 million was determined by subtracting the amount of Adjusted Test Year electric operating income at present rates of $273.1 million obtained from AES Indiana Financial Exhibit AESI-OPER, Schedule OPINC,[5] column 3, line 13, from the allowable electric operating income requirement of $417.2 million (Schedule REVREQ1, line 3). The deficiency in electric operating revenue of $192.9 million on AES Indiana Financial Exhibit AESI-REVREQ, Schedule REVREQ1, line 7 was determined by dividing the deficiency in electric operating income (line 5) by the revenue conversion factor (line 6). This amount was utilized in the determination of the rates proposed by AES Indiana witness Rimal in this Cause. The additional electric operating revenue of $192.9 million proposed in this Cause corresponds to the amount on AES Indiana Financial Exhibit AESI-OPER, Schedule OPINC, column 4, line 1. As discussed below, the Company proposes to phase in the rate increase in two steps.

3. RATE BASE

Q15. Please describe the adjustment on AES Indiana Financial Exhibit AESI-RB, Schedule RB3 to remove Eagle Valley Forced Outage Capital Costs.

A15. In the Settlement Agreement approved in Cause No. 38703 FAC 133 S1, AES Indiana agreed the "Company shall not seek, nor be permitted to earn, a return 'on' any capital

[4] AES Indiana Financial Exhibit AESI-RB, Schedule RB1 is sponsored by AES Indiana witness Peters.
[5] AES Indiana Financial Exhibit AESI-OPER, Schedule OPINC is sponsored by AES Indiana witness Peters.

investment incurred to repair and replace equipment as a result of the Outage…."[6] In addition, the Company agreed to make a reduction to retail jurisdictional Utility Plant in Service net of accumulated depreciation.[7] This adjustment was first implemented in Cause No. 45911 and is continued in this proceeding. On AES Indiana Financial Exhibit AESI-RB, Schedule RB3, $10.2 million of the unamortized Eagle Valley Forced Outage capital repair costs, net of accumulated depreciation, is removed from the Adjusted Test Year rate base balance. This net amount is then reflected in the total regulatory assets not included in rate base shown on AES Indiana Financial Exhibit AESI-RB, Schedule RB8 to allow for amortization without a return in compliance with the Settlement Agreement.

Q16. Please discuss the adjustment on AES Indiana Financial Exhibit AESI-RB, Schedule RB4 made to remove non-jurisdictional MISO MTEP plant in service.

A16. AES Indiana witness Holtsclaw[8] discusses certain types of capital projects, which can be constructed as part of the MTEP, and the cost allocation and recovery of these project costs through the FERC-approved MISO Tariff. In its Order in Cause No. 44576 (on pages 24 & 50), the Commission found AES Indiana's treatment of projects subject to MISO regional cost allocation as non-jurisdictional to be reasonable and consistent with the treatment of the same project costs for other Indiana electric utilities. In Cause Nos. 44576, 45029, and 45911, the Commission accepted AES Indiana's proposed adjustments to remove the impact of MISO MTEP projects from rate base, revenues, and expenses, and to recover all allocated Schedule 26, 26-A, and 26-C charges through the RTO rider.

[6] Cause No. 38703 FAC 133 S1 Settlement Agreement, p. 3.
[7] *Id.*
[8] AES Indiana witness Holtsclaw, Direct Testimony, Section 6.

In this proceeding, AES Indiana proposes to continue this approach and has reflected adjustments to remove the rate base and operating income statement impact of the MTEP projects that are included on Attachment GG filed annually with MISO.[9] The MTEP projects are discussed by AES Indiana witness Holtsclaw.[10]

To remove the rate base impact, AES Indiana prepared AES Indiana Financial Exhibit AESI-RB, Schedule RB4, which I sponsor. $20.8 million of utility plant (line 7) and $9.5 million of accumulated depreciation (line 10) as of December 31, 2026, are removed. If this adjustment was not made, rate base would improperly reflect this $11.3 million of non-jurisdictional net plant.

To remove the operating income statement impacts, AES Indiana prepared multiple adjustments, two of which I am sponsoring. On AES Indiana Financial Exhibit AESI-OPER, Schedule REV8, line 3, $3.0 million of non-jurisdictional Schedule 26 revenues forecasted from MISO during 2026 for these projects are removed. On AES Indiana Financial Exhibit AESI-OPER, Schedule OM10, $1.2 million of allocated O&M related to the projects is removed. The allocation is consistent with the annual allocation factor from the Company's Attachment GG template filed with MISO that is used as the basis for recovery of these projects from MISO.

The remaining income statement impacts are sponsored by AES Indiana witnesses Peters and Miller. AES Indiana witness Peters[11] supports the calculation of forecasted

[9] Attachment GG is a standardized rate formula template which uses FERC Form 1 Data to quantify an annual revenue requirement for specific projects subject to shared cost allocation and recovery.
[10] AES Indiana witness Holtsclaw, Direct Testimony Section 6.
[11] AES Indiana witness Peters, Direct Testimony, Section E.

depreciation expense shown on AES Indiana Financial Exhibit AESI-OPER, Schedule DEPR. This schedule excludes the non-jurisdictional MISO MTEP plant.

AES Indiana witness Miller[12] supports the calculation of federal and state income taxes on income incorporating the above adjustments on AES Indiana Financial Exhibit AESI-OPER, Schedules TX2 and TX3.[13] If these adjustments were not made, operating revenues and expenses would improperly include these non-jurisdictional revenues and expenses.

4. REGULATORY ASSETS INCLUDABLE IN RATE BASE

Q17. Please describe the Regulatory Assets shown on AES Indiana Financial Exhibit AESI-RB, Schedule RB8.

A17. See AES Indiana Attachment KA-1 for a summary of the regulatory assets on AES Indiana Financial Exhibit AESI-RB, Schedule RB8 which includes amortization periods and any proposed changes to amortization periods. A more detailed description of each is also included below.

Q18. Please describe the balances on AES Indiana Financial Exhibit AESI-RB, Schedule RB8.

A18. The Company has included forecasted balances for regulatory assets includable in rate base as of the end of the Linking Period (calendar year 2025) and Adjusted Test Year (calendar year 2026), as well as the May 31, 2026, balances used as the basis for forecasting ongoing amortization expense as described further below.

[12] AES Indiana witness Miller, Direct Testimony, Q/A 18.
[13] AES Indiana Financial Exhibit AESI-OPER, Schedules TX-2 and TX-3 are sponsored by AES Indiana witnesses Miller and Peters.

Phase 1 rate base includes regulatory asset balances as of December 31, 2025, for regulatory assets that have existed since the last rate case, as well as regulatory assets being included in rate base for the first time in this proceeding. These balances were calculated by taking the actual Historical Base Period (December 31, 2024) balances and forecasting amortization through December 31, 2025, to arrive at the Phase 1 balances.

The May 31, 2026 balances on this schedule are used to calculate the forecasted going level of amortization. There are several assets forecasted to be fully amortized either during 2026 or in less than three years after an Order is anticipated in this proceeding. For these assets, amortization was re-calculated using the May 31, 2026, balance and spread over a proposed three-year amortization period. This was done in order to ensure full recovery of the assets that are forecasted to be fully amortized before the end of calendar year 2026 and also to prevent the need to remove assets that are fully recovered in less than three years. These assets are indicated by an asterisk (*) and the change to the amortization periods is described on <u>AES Indiana Attachment KA-1</u>.

The December 31, 2026, Adjusted Test Year forecast was used to calculate rate base for Phase 2 rates in this proceeding. The forecasted balances were calculated similar to as described above forecasting amortization through December 31, 2026. Annual amortization expense will not change from Phase 1 to Phase 2.

Petersburg Unit 4* – The first item listed on <u>AES Indiana Attachment KA-1</u> was included in the original cost rate base in Cause Nos. 44576, 45029, and 45911. The costs relate to the construction of Petersburg Unit 4 and for the deferred depreciation and post-in-service AFUDC and carrying charges incurred from the in-service date through the date of the

Commission's Order in Cause No. 37837 including Petersburg Unit 4 in rates. AES Indiana Attachment KA-1, line 3, reflects the total of these costs (whose May 31, 2026, balances total $0.3 million) amortized over three years for a forecasted annual amortization expense of $0.09 million.

Environmental Projects – The second two items listed on AES Indiana Attachment KA-1 consist of post-in-service AFUDC, carrying charges and deferred depreciation incurred for multiple environmental projects approved for recovery in AES Indiana's Environmental Compliance Cost Recovery Adjustment ("ECCRA") that were included in the original cost rate base approved in Cause Nos. 44576, 45029 and 45911 as further described below.

The Nitrogen Oxides ("NO_x"), Multi-Pollutant Plan ("MPP"), and MPP2 clean coal technology projects approved in the Commission's Orders in Cause Nos. 42170, 42700, and 43403 rolled into basic rates and the regulatory assets were included in the original cost rate base approved in Cause Nos. 44576, 45029 and 45911. The Mercury and Air Toxic Standards ("MATS") rule Compliance Project approved in Cause No. 44242, the National Pollutant Discharge Elimination System ("NPDES") permit Compliance Project and the Harding Street 7 ("HS7") Refueling Project approved in Cause No. 44540, rolled into basic rates and the regulatory assets were included in the original cost rate base approved in Cause No. 45029. As shown on line 4 of AES Indiana Attachment KA-1, a total of $6.9 million for these projects is forecast to remain unamortized as of December 31, 2026 for the post-in-service AFUDC. The costs for HS7 are being amortized over the life of the assets consistent with Cause No. 45029. The remaining Environmental Projects on this line will continue to be amortized over ten years consistent with Cause No. 45911 for an annual amortization expense of $1.0 million. As shown on line 5 of AES Indiana Attachment KA-1, a total of $9.1 million for these projects is forecast to remain unamortized as of December 31, 2026 for the deferred depreciation. The annual amortization expense of $1.4 million maintains the ten-year amortization period consistent with the Cause No. 45911 Settlement Agreement.

National Ambient Air Quality Standards-Di-Basic Acid ("NAAQS-DBA") – In its Order in Cause No. 44794, the Commission authorized recovery through the ECCRA of AES Indiana's NAAQS Compliance Project. The DBA system of the NAAQS Compliance Project rolled into base rates and the regulatory assets were included in the original cost rate base approved in Cause Nos. 45029 and 45911. The depreciation deferred of $25 thousand and the post-in-service AFUDC of $50 thousand forecasted to remain unamortized is shown on lines 6 and 7, respectively. The ten-year amortization period is consistent with the Cause No. 45911 Settlement Agreement.

Coal Combustion Residuals ("CCR") Bottom Ash – Also in its Order in Cause No. 44794, the Commission authorized recovery through the ECCRA of AES Indiana's CCR Compliance Project. This project was included in base rates in Cause No. 45029 as a Major Addition and included in the regulatory assets in Cause No. 45911. The deferred depreciation of $0.6 million and post in-service AFUDC of $0.3 million is shown on lines 8 and 9, respectively. The forecasted annual amortization expense is consistent with the ten-year amortization in the Cause No. 45911 Settlement Agreement.

NAAQS-Other – The remainder of the NAAQS Compliance Project (NAAQS non-DBA or NAAQS-Other) not included in base rates in Cause No. 45029 was included in Utility

Plant in Service in Cause No. 45911. The deferred depreciation balance of $0.3 million and post in-service AFUDC of $0.2 million are shown on lines 10 and 11, respectively. The annual amortization expense is consistent with the ten-year amortization period in the Cause No. 45911 Settlement Agreement.

Eagle Valley CCGT and Harding Street 5 & 6 – The next two items on AES Indiana Attachment KA-1 (lines 12 and 13) are the deferred depreciation balances of $13.0 million and post in-service AFUDC of $26.7 million related to the Eagle Valley CCGT and Harding Street 5 & 6 refueling projects approved in Cause No. 44339. These projects were placed in service and rolled into base rates in Cause No. 45029 and 45911 and are being amortized over the life of the assets as approved in Cause No. 44339.

Electric Vehicle* – In its Order in Cause No. 44478, the Commission authorized AES Indiana to defer the costs for extension of electric facilities for the BlueIndy Project, including carrying costs, until such costs are recognized in a subsequent rate case. This regulatory asset was included in base rates in Cause Nos. 45029 and 45911. On line 14, AES Indiana has reflected the forecasted deferred balance as of December 31, 2026, of $0.2 million and annual amortization of $87 thousand over three years.

Harding Street Unit 7 ("HS7") Preservation* – In its Order in Cause No. 42170 ECR-26, the Commission authorized AES Indiana to create a regulatory asset for the compliance costs related to HS7 incurred for the MATS Compliance Project authorized in Cause No. 44242 to be amortized over ten years and included in the recoverable MATS Compliance Projects costs in the ECCRA. This project was included in base rates in Cause No. 45029 and 45911. As shown on line 15, the deferred balance for these Preservation Costs as of

December 31, 2026, is forecasted to be zero, with an annual amortization of $12 thousand for three years using the forecasted May 31, 2026, balance.

Harding Street 7 Gas Conversion/National Pollutant Discharge Elimination System ("NPDES")* – In its Order in Cause No. 44540, the Commission authorized AES Indiana to create a regulatory asset for the remaining twenty percent (20%) of the capital, operating, maintenance, depreciation, tax and financing costs (revenue requirement) for the NPDES and HS7 Compliance Project not timely recovered through the ECCRA, with carrying costs, until such costs are reflected in the Company's retail electric rates. These projects were included in base rates in Cause Nos. 45029 and 45911 and on line 16, AES Indiana has reflected the forecasted deferred balance for the HS7 Gas Conversion as of December 31, 2026, of $(0.9) million. The annual amortization of $(0.4) million over four years is consistent with Cause No. 45911.

On line 17, AES Indiana has reflected the forecasted deferred balance for the NPDES projects at Petersburg and Harding Street as of December 31, 2026, of $6.3 million. The annual amortization of $2.8 million over three years is proposed in this proceeding.

NAAQS-DBA/CCR Bottom Ash/NAAQS-Other* – In its Order in Cause No. 44794, the Commission authorized AES Indiana to create a regulatory asset for the remaining twenty percent (20%) of the capital, operating, maintenance, depreciation, tax and financing costs (revenue requirement) for the NAAQS-DBA, CCR Bottom Ash and NAAQS-Other projects not timely recovered through the ECCRA, with carrying costs, until such costs are reflected in the Company's retail electric rates. As mentioned previously, NAAQS-DBA and CCR Bottom Ash were included in base rates in Cause Nos. 45029 and 45911 and the

NAAQS-Other project was included in base rates in this Cause No. 45911. On lines 18-20, AES Indiana has included the forecasted December 31, balances of $0.3 million for NAAQS-DBA, $0.7 million for CCR Bottom Ash, and $1.7 million for NAAQS-Other, respectively. The annual amortization is based on the proposed three year amortization of the May 31, 2026 forecasted balances as discussed above.

Petersburg Unit 1 and Units 1 & 2 Shared Assets – The Petersburg Units 1 and 2 regulatory assets were created in accordance with the Settlement Agreement approved in Cause No. 45502 and included in rate base in Cause No. 45911. On line 21, AES Indiana has included the forecasted unamortized balance of $18.3 million for the Petersburg Unit 1 capital costs and a $5.0 million annual amortization consistent with Cause No. 45911.

On line 22, AES Indiana has included the forecasted unamortized balance of $78.0 million for Petersburg Unit 2, and Units 1 and 2 shared assets, which is being amortized over ten years consistent with Cause No. 45911.

TDSIC* – In its Order in Cause No. 45264 approving AES Indiana's Transmission, Distribution, and Storage System Improvement Charge Plan ("TDSIC Plan"), the Commission authorized the Company to create regulatory assets for deferred depreciation and post-in-service AFUDC associated with the projects until such costs are reflected in the rider. On lines 23 and 24, AES Indiana has forecasted the deferred balance of $22.1 million for deferred depreciation and $45.2 million for post-in-service AFUDC as of December 31, 2026 with an annual amortization[14] of $0.6 million and $1.1 million, respectively. The Order in Cause No. 45264 TDSIC-1 authorized the Company to record

[14] Based on 36.3 year amortization period.

as a regulatory asset, 20% of the TDSIC tracker revenue requirement (including depreciation expense, property taxes and pretax returns) with carrying costs until such costs are reflected in retail electric rates. The deferred balances are forecasted to be $32.0 million for Distribution (line 25) and $5.6 million for Transmission (line 26), amortized over three years for $9.0 million and $1.6 million per year, respectively. These TDSIC regulatory assets include the unamortized balance of deferrals for projects that rolled into base rates in Cause No. 45911 as well as deferrals for more recent TDSIC projects rolling into base rates for the first time in this rate case.

Hardy Hills Joint Venture – In its Order in Cause Nos. 45493 and 45493 S1, the Commission authorized AES Indiana to create regulatory assets for the investment in the Hardy Hills project, project development costs and carrying charges on the investment until such costs are reflected in retail electric rates. The Company was authorized to include these costs in the ECCRA and is requesting the same treatment in this proceeding (both a return on and return of) as is occurring in the ECCRA. In AES Indiana's compliance filing in this Cause, the Company will update the ECCRA schedules to remove these projects from the rider adjustment factor. On line 27, AES Indiana has included the forecasted unamortized December 31, 2026 balance of $252.1 million to be amortized over the remaining life of the assets for an annual amortization of $7.9 million.

Petersburg Energy Center Joint Venture – In its Order in Cause Nos. 45591 and 45832, the Commission authorized AES Indiana to create regulatory assets for the investment in the Petersburg Energy Center project, project development costs and carrying charges on the investment until such costs are reflected in retail electric rates. The Company was authorized to include these costs in the ECCRA and is requesting the same treatment in this proceeding (both a return on and return of) as is occurring in the ECCRA. In AES Indiana's compliance filing in this Cause, the Company will update the ECCRA schedules to remove these projects from the rider adjustment factor. On line 28, AES Indiana has included the forecasted unamortized December 31, 2026 balance of $280.7 million to be amortized over the remaining life of the assets for an annual amortization of $8.1 million.

Pike County Battery Energy Storage System ("BESS") Joint Venture – In its Order in Cause No. 45920, the Commission authorized AES Indiana to create regulatory assets for the investment in the Pike County BESS project, project development costs and carrying charges on the investment until such costs are reflected in retail electric rates. The Company was authorized to include these costs in the ECCRA and is requesting the same treatment (both a return on and return of) as is occurring in the ECCRA. In AES Indiana's compliance filing in this Cause, the Company will update the ECCRA schedules to remove these projects from the rider adjustment factor. On line 29, AES Indiana has included the forecasted unamortized December 31, 2026 balance of $168.5 million to be amortized over the remaining life of the assets for an annual amortization of $9.0 million.

Hoosier Wind – In its Order in Cause No. 45931, the Commission authorized AES Indiana to defer in regulatory assets the costs associated with the acquisition of the Hoosier Wind project to be timely recovered in the Company's ECCRA filings until such costs are included in a base rate case. The Company was authorized to include these costs in the ECCRA and is requesting the same treatment (both a return on and return of) as is occurring in the ECCRA. In AES Indiana's compliance filing in this Cause, the Company will update the ECCRA schedules to remove these projects from the rider adjustment factor. On line 30, AES Indiana has included the forecasted unamortized December 31, 2026 balance of

$45.8 million to be amortized over the remaining life of the assets for an annual amortization of $3.8 million.

ACE Project Capital Costs – In the Settlement Agreement approved in Cause No. 45911, the Commission authorized AES Indiana to recover capital costs for developing and implementing the ACE Project.[15] In the Settlement Agreement, the settling parties agreed to include $94.2 million.[16] However, after the Settlement Agreement was finalized, witness Rogers' settlement testimony reflected a reduction in the ACE Capital Costs to $83.9 million.[17] This updated amount was accepted by the settling parties and included in the Addendum to the Settlement Agreement as explained and included in the Company's Response to the Commission's Docket Entry Dated December 14, 2023. Subsequently, in determining the amount of the ACE Project Costs that could be recorded to Utility Plant In Service ("UPIS"), there was a portion deemed to not be capitalized to the UPIS accounts for accounting purposes. These costs (originally $3.2 million) were recorded as a regulatory asset to reflect recovery of the full $83.9 million consistent with the Settlement Agreement. Recording these costs as a regulatory asset was also necessary so that the Company can recognize amortization expense consistent with the depreciation expense on the total $83.9 million for ratemaking in Cause No. 45911. As of December 31, 2026, the forecasted unamortized balance is $2.2 million, which is amortized over ten years consistent with Cause No. 45911.

[15] Cause No 45911 Settlement Agreement p. 2
[16] *Id.*
[17] Cause No. 45911 Rogers Settlement Testimony p. 10

Electric Vehicle Portfolio – In its Order in Cause No. 45843, the Commission authorized AES Indiana to defer EV Portfolio costs and record a regulatory asset with carrying charges, for recovery in a subsequent base rate case. On line 32, AES Indiana has forecasted a regulatory asset balance of $12.0 million amortized over a proposed three years with an annual amortization of $2.9 million.

Petersburg Units 3 & 4 Repowering – In its Order in Cause No. 46022, the Commission authorized AES Indiana to defer the net materials and supplies inventory that will no longer be used as a part of the Repowering Project as well as the remaining net book value of the retired assets associated with the repowering of Petersburg Units 3 and 4. On lines 33 and 34, AES Indiana has included a forecasted regulatory asset balance of $112.6 million as of December 31, 2026 which reflects the remaining unamortized balance of the net materials and supplies inventory and remaining net book value of the retired assets associated with Repowering Project. The associated annual amortization of $13.0 million is consistent with the Orders in Cause Nos. 46022, 45911, and 44242.

Q19. Please describe the Regulatory Assets shown on <u>AES Indiana Financial Exhibit AESI-RB, Schedule RB8</u> but not included in Rate Base.

A19. The first item on line 39 relates to a Settlement Agreement approved by the Commission in Cause No. 38703 FAC 133S1. As discussed previously (Q/A 15), the Company agreed that it would not seek a return "on" the capital repair costs related to the forced outage at the Eagle Valley CCGT. In order to effectuate this term of the Settlement Agreement, AES Indiana agreed to reduce the retail jurisdictional Utility Plant in Service and create a regulatory asset to be amortized over 25 years. As shown on line 39, this results in a forecasted regulatory asset balance of $10.2 million as of December 31, 2026 (net of accumulated depreciation and net of insurance recovery) which is not included in total rate base but is included on this schedule to calculate amortization. Also reflected on line 39, column 3, is the annual amortization of $0.4 million over 25 years as approved in the Settlement Agreement.

The second item on line 40 relates to the regulatory asset created as a result of the Order in Cause No. 45380, where the Commission authorized AES Indiana to create a regulatory asset for COVID-19 related impacts directly associated with the prohibition of utility disconnects, collection of certain utility fees, as well as COVID-19 related uncollectible and incremental bad debt expense. The total forecasted unamortized balance as of December 31, 2026 is $0.5 million with a three-year amortization of the forecasted May 31, 2026, balance in this proceeding, resulting in an annual amortization of $0.4 million.

Q20. Are there other Regulatory Assets that AES Indiana has excluded from rate base that are not shown on AES Indiana Financial Exhibit AESI-RB, Schedule RB8?

A20. Yes. In its Order in Cause No. 46113, the Commission authorized AES Indiana to create a regulatory asset for AES Indiana's investment in the Crossvine Project ("Crossvine") along with the project development costs. As discussed in my testimony in that Cause, AES Indiana requested to begin amortization and recovery of the project in the existing and ongoing annual ECCRA filings.

5. REVENUE ADJUSTMENTS

Q21. Please explain the adjustments to revenue on AES Indiana Financial Exhibit AESI-OPER, Schedule REV5.

A21. The purpose of the adjustments on AES Indiana Financial Exhibit AESI-OPER, Schedule REV5 is to take total adjusted forecasted rate revenue at existing basic rate tariffs (from AES Indiana Financial Exhibit AESI-OPER, Schedule REV4) to total electric retail revenues for the Adjusted Test Year at present rates. This roll forward is accomplished by adding back the forecasted levels of revenues from the Company's FAC, ECCRA, DSM lost revenue, CAP, OSS, RTO, and TDSIC rate adjustment mechanisms. The balances by line item from this schedule match the Adjusted Test Year Revenues at Present Rates on AES Indiana Financial Exhibit AESI-OPER, Schedule REV1, column 3.[18]

The Adjusted Test Year Rider 6 FAC revenues were calculated based upon forecasted kilowatt hours multiplied by the difference between the current base cost of fuel and the new base cost of fuel per kWh on AES Indiana Financial Exhibit AESI-OPER, Schedule OM2, so the total forecasted fuel revenue matches total forecasted fuel expense. The Adjusted Test Year Rider 20 ECCRA revenues reflect the forecasted annualized ECCRA revenues for the completed Hardy Hills, Petersburg Energy Center, Pike County BESS, and Hoosier Wind projects which will move into base rates. The Adjusted Test Year Rider 22 DSM Lost Revenues reflect the lost revenues forecasted for the Adjusted Test Year which will be rolling into base rates.

The Adjusted Test Year Rider 24 CAP revenues of $30.8 million reflect a forecasted credit to AES Indiana's jurisdictional customers through the CAP rider. This adjustment reflects the assumption that the CAP rider benchmark is expected to change from a charge of $19.0 million in Cause No. 45911, to a credit of $8.9 million as reflected on AES Indiana

[18] AES Indiana Financial Exhibit AESI-OPER, Schedule REV1 is sponsored by AES Indiana witness Peters.

Financial Exhibit AESI-OPER, Schedule REV9. The Adjusted Test Year Rider 25 OSS revenues reflect a forecasted charge of $3.7 million based upon the forecasted decrease to the OSS benchmark from $28.6 million established in Cause No. 45911 to $24.9 million as reflected on AES Indiana Financial Exhibit AESI-OPER, Schedule REV6. The Adjusted Test Year Rider 26 RTO revenues were calculated based upon the proposed change in the benchmark for net MISO non-fuel costs and revenues shown on AES Indiana Financial Exhibit AESI-OPER, Schedules REV8 and OM13. The RTO benchmark is forecasted to decrease from $32.2 million established in Cause No. 45911 to $29.6 million in this proceeding. The Adjusted Test Year Rider 3 TDSIC revenues represent the annualized forecasted revenue requirement of TDSIC projects that are forecasted to be in-service as of December 31, 2026, that will move into base rates.

Q22. Please describe AES Indiana Financial Exhibit AESI-OPER, Schedule REV8 related to MISO.

A22. Line 2 on this schedule reflects MISO Jurisdictional Transmission Revenue used to calculate the benchmark for the RTO rider discussed later in my testimony. The forecasted MISO jurisdictional revenues of $3.6 million from AES Indiana Financial Exhibit AES-OPER, Schedule REV8 are combined with MISO non-fuel costs to determine the new benchmark used in the RTO rider filings.

On line 4, an adjustment was made to appropriately include a forecast for MISO Balancing Authority Credits as revenue, consistent with how these credits are being treated in the annual RTO rider filings. The offsetting adjustment can be seen on AES Indiana Financial Exhibit AES-OPER, Schedule OM13, line 12. The amount on line 7 is the revenue portion of the annual MISO Deferred Expense Amortization as shown on AES Indiana Financial Exhibit AESI-OPER, Schedule OM14.

6. STORM EXPENSE ADJUSTMENT AND MAJOR STORM DAMAGE RESTORATION RESERVE

Q23. Please explain AES Indiana Financial Exhibit AESI-OPER, Schedule OM11.

A23. AES Indiana witness Holtsclaw discusses the recent history of the number of storms by level that have occurred and supports the forecasted storm expense. As shown on this schedule (line 1), the Adjusted Test Year includes $11.9 million for Level 1 & 2 storms.

Additionally, as also discussed by AES Indiana witness Holtsclaw, AES Indiana experienced two qualifying storm events that were charged to the Major Storm Reserve in 2023 and 2024. Consequently, as shown on this schedule (line 12) there is a shortfall of $4.7 million which will be added to the benchmark for Level 3 & 4 storm expense in the Major Storm Reserve account as a result of qualifying storm events that occurred in recent years.

Q24. Please discuss the Major Storm Damage Restoration Reserve AES Indiana is proposing in this proceeding.

A24. In Cause No. 44576, the Commission accepted the creation of a Major Storm Damage Restoration Reserve account which continued in Cause Nos. 45029 and 45911. The credit balance that existed in Cause No. 45911 is being amortized over three years consistent with the Settlement Agreement in that Cause.

As can be seen at the bottom of AES Indiana Financial Exhibit AESI–OPER, Schedule OM11, due to the recent qualifying storm activity, AES Indiana projects that as of

December 31, 2026, there would be a balance of $14.1 million in the Major Storm Regulatory Asset. This balance includes an additional forecasted reserve for the April 2, 2025 storm that impacted AES Indiana service territory discussed by AES Indiana witness Holtsclaw. AES Indiana proposes to amortize this balance over three years, resulting in a forecasted annual true up of the storm reserve balance of $4.7 million, which will be recorded against the Major Storm Regulatory Asset. The total major storm reserve benchmark and true up for the Adjusted Test Year is $12.0 million.

7. VEGETATION MANAGEMENT RESERVE

Q25. Please discuss the Vegetation Management Reserve that AES Indiana is proposing to continue in this proceeding.

A25. The Order in Cause No. 45911 approved a Settlement Agreement, which included $25.247 million of vegetation management in base rates for distribution facilities by third-party contractors. Additionally, AES Indiana agreed to defer any shortfalls in annual vegetation management costs relative to the amount in base rates. This deferral mechanism serves as a cap and no amounts spent above the amount in base rates on a cumulative basis are deferred. Finally, AES Indiana agreed that in the next base rate case, any balance in this regulatory liability would be amortized into the cost of service as a credit to ratepayers As of the date of this filing, there is no balance in the regulatory liability and AES Indiana is not forecasting to have a balance in the Adjusted Test Year.

AES Indiana proposes to continue to utilize the same methodology as accepted in Cause Nos. 45029 and 45911. As shown on <u>AES Indiana Financial Exhibit AESI-OPER,</u>

Schedule OM12 and as discussed by AES Indiana witness Flint,[19] AES Indiana forecasts annual vegetation management expenses of $42.6 million for the Distribution System. Each month, beginning with the first month in which AES Indiana implements final approved rates following the issuance of an Order in this Cause, one twelfth (1/12) of the annual $42.6 million revenue requirement for Distribution vegetation management O&M expenses will be compared with the actual Distribution vegetation management O&M expenses. If the incurred Distribution O&M expenses are less than the monthly amount reflected in the revenue requirement, AES Indiana will record an increase to expense for the difference, with a corresponding credit to Account 254 – Other Regulatory Liabilities. Expenses incurred over and above the embedded amount, on a cumulative basis, will deplete any credit in Account 254 but will not be deferred.

8. MISO NON-FUEL COSTS

Q26. Please describe AES Indiana Financial Exhibit AESI-OPER, Schedule OM13 for MISO non-fuel costs.

A26. As shown on AES Indiana Financial Exhibit AESI-OPER, Schedule OM13 AES Indiana is forecasting $33.2 million for the annual level of expense for MISO non-fuel costs. This level of expense will be the basis for the new benchmark used to calculate the RTO adjustment after the effective date of rates approved in this proceeding. AES Indiana budgets MISO non-fuel costs on a calendar year basis (dividing evenly to determine monthly amounts) using two methodologies. For Schedule 26 and 26-A charges, the estimates are based on data found in the MISO MTEP for charges by other market

[19] AES Indiana witness Flint, Direct Testimony, Q/A 25.

participants applicable to AES Indiana, which include estimates of the portion of AES Indiana's MTEP cost-shared projects that are allocable to AES Indiana. For the remaining costs, AES Indiana looks at historical information and prior forecasts and incorporates known or expected changes in developing the annual budget. On line 12, MISO Balancing Authority Credits are removed from this schedule and accounted for as revenue, consistent with how these credits are being treated in the annual RTO rider filings. The offsetting adjustment can be seen on AES Indiana Financial Exhibit AES-OPER, Schedule REV8, line 4.

Q27. Please describe AES Indiana Financial Exhibit AESI-OPER, Schedule OM14.

A27. The MISO non-fuel costs were deferred in accordance with the Orders in Cause Nos. 42266, 42685, and 42962 through the effective date of the rates approved in Cause No. 44576. AES Indiana Financial Exhibit AESI-OPER, Schedule OM14 reflects the forecast unamortized balance and continued amortization of the regulatory asset for MISO non-fuel costs. Since these costs are forecast to be fully amortized during 2026, AES Indiana proposes to amortize the forecast balance as of May 31, 2026, over three years. This schedule reflects an annual level of amortization of $0.7 million, net of revenue amortization (see corresponding entry on AES Indiana Financial Exhibit AESI-OPER, Schedule REV8).

9. <u>OTHER O&M EXPENSES</u>

Q28. Please describe the adjustment on <u>AES Indiana Financial Exhibit AESI-OPER, Schedule OM18</u>.

A28. In the Settlement Agreement approved in Cause No. 45911, AES Indiana was authorized to amortize the one-time O&M costs related to the ACE Project over a period of four years. The adjustment on this schedule represents the proposed annual amortization of $1.4 million over three years based on the forecasted unamortized balance of $4.2 million as of May 31, 2026. As explained above, for regulatory assets with fewer than three years of amortization remaining, the Company is proposing a three-year amortization of these costs for ease of administrative burden even though it results in a longer recovery period than previously authorized.

Q29. Please describe the adjustment on <u>AES Indiana Financial Exhibit AESI-OPER, Schedule OM21</u> that you sponsor.

A29. I sponsor the adjustment on line 16 to add the total forecast unamortized 2023 rate case expenses AES Indiana was authorized to recover in Cause No. 45911. For ease of administrative burden, AES Indiana is proposing a three-year amortization of all rate case expenses even though that results in a longer recovery period for Cause No. 45911 expenses. AES Indiana witness Peters sponsors the remainder of this schedule.

Q30. Please describe the adjustments on <u>AES Indiana Financial Exhibit AESI-OPER, Schedule OM22</u>.

A30. These adjustments were made to remove O&M related to costs that will be fully recovered via rate adjustment mechanisms (Green Power and DSM programs) or customer specific rates (Electric Vehicle) and not incorporated into new base rates.

10. <u>CURRENT RATE ADJUSTMENT RIDERS</u>

Q31. Please list AES Indiana's current rate adjustment riders.

A31. AES Indiana's eight current rate adjustment riders are listed in Table KA-1 below:

Table KA-1: AES Indiana Current Rate Adjustment Riders

Standard Contract Rider No.		
3	Transmission, Distribution, and Storage System Improvement Charge (TDSIC)	No change
6	Fuel Cost Adjustment (FAC)	New base cost of fuel
20	Environmental Compliance Cost Recovery Adjustment (ECCRA)	Proposed changes to benchmark for consumables; continued tracking of allowances; and recovery of Petersburg Repowering costs not included in base rates.
21	Green Power Initiative (GPI)	No change
22	Demand-Side Management Adjustment (DSM)	No change
24	Capacity Adjustment (CAP)	Proposed language changes and new benchmark
25	Off-System Sales Margin (OSS Margin)	Proposed change to benchmark
26	Regional Transmission Organization Adjustment (RTO)	Proposed change to benchmark

Q32. Does AES Indiana propose to continue each of these rate adjustment riders after the issuance of an Order in this proceeding?

A32. Yes. AES Indiana is not proposing substantive changes to the current rate adjustment riders. As discussed previously, AES Indiana is proposing to continue to recover all expenses for DSM and GPI in their respective rate adjustment riders. Therefore, such costs have no impact on pro forma net operating income at present rates or the requested revenue increase in this proceeding. In addition, AES Indiana is proposing to adjust the then-current rate adjustment riders for costs which will be reflected in the new basic rates and charges resulting from this proceeding.

Q33. Please identify the rate adjustment riders that you are proposing to change.

A33. AES Indiana is proposing modifications to the FAC, ECCRA, CAP, OSS, and RTO riders as discussed in more detail below.

Q34. Please explain the proposed modifications to the FAC rate adjustment rider.

A34. As discussed by AES Indiana witness Dickerson,[20] AES Indiana proposes a new base cost of fuel (see AES Indiana Financial Exhibit AESI-OPER, Schedule OM2). In addition, AES Indiana proposes to modify the language on the FAC rider to change the base amount of fuel used to calculate the FAC adjustment factor on the tariff to \$0.044940 per kWh (instead of the current \$0.039027), which has been reflected on the proposed Standard Contract Rider No. 6 (FAC) in AES Indiana witness Baker, Attachment AJB-1.

[20] AES Indiana witness Dickerson, Direct Testimony, Q/A 21.

When new tariff sheets are filed based upon the final Order in this proceeding, AES Indiana proposes to adjust the then current FAC factor to reflect the new base cost of fuel as of the same effective date.

Q35. Please explain the proposed modifications to the ECCRA rate adjustment rider.

A35. As discussed by AES Indiana witness Steiner, the Company is proposing to modify the language of the ECCRA rider to update the benchmark amount of consumables used to calculate the ECCRA adjustment factor. The inclusion of a consumables benchmark is consistent with the Settlement Agreement approved in Cause No. 45911. The ECCRA rider will also continue to reflect the actual sales or purchases made for emissions allowances during the reconciliation period. This is consistent with current practice included in the Settlement Agreement approved in Cause No. 45911. These changes have been reflected on Standard Contract Rider No. 20 (ECCRA) in AES Indiana witness Baker, Attachment AJB-1.

Additionally, as discussed by AES Indiana witness Ellis, the Petersburg Repowering Project is currently underway. In its Order in Cause No. 46022, the Commission issued a certificate of public convenience and necessity under Ind. Code § 8-1-8.5-2 and approved the Petersburg Repowering Project as a clean energy project under Ind. Code § 8-1-8.8-11. The Commission also approved the Company's proposed accounting and ratemaking treatment in that Cause for deferral of project costs including depreciation expense, carrying charges, property taxes and the decommissioning and retirement of certain assets associated with coal operations to be recovered in a future base rate case. As discussed by AES Indiana witness Rogers in Cause No. 46022, cost recovery through a base rate case or the ECCRA tracker mechanism would produce a similar rate impact.[21] The Company proposed deferral treatment in Cause No. 46022 because the project lined up well with this planned rate case. The Company expects to complete this project in December 2026, however, if the repowering of Petersburg is not completed by the end of the Adjusted Test Year, the Company is proposing to include the deferred balances approved for recovery in a subsequent ECCRA filing after an Order in this proceeding. Similar to approvals for other clean energy projects,[22] the use of the ECCRA will reduce the overall balance of the regulatory asset and resulting revenue requirement as of the time it will be included in a subsequent base rate case.

Q36. Does Ind. Code §. 8-1-8.8 authorize rate adjustments for clean energy project costs, such as the Petersburg Repowering Project?

A36. Yes. Ind. Code § 8-1-8.8-11 states that:

> the commission shall encourage clean energy projects by creating the following financial incentives for clean energy projects, if the projects are found to be just and reasonable: (1) the timely recovery of costs and expenses incurred during construction and operation [of clean energy projects].

Ind. Code § 8-1-8.8-11 also states that the Commission may not approve a financial incentive unless the Commission finds that timely recovery is: "(A) just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing costs savings over the life of the project."

Q37. Has the Petersburg Repowering Project been found just and reasonable?

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[21] Cause No. 46022, Rogers Direct testimony p. 10.
[22] Cause No. 46113 Crossvine Project, Cause Nos. 45591/45832 Petersburg Energy Center, Cause No. 45920 Pike County BESS.

A37. Yes. In its Order in Cause No. 46022, the Commission found that the Project is just and reasonable within the meaning of Ind. Code § 8-1-8.8-11.

Q38. Will timely recovery of construction financing costs result in a gross financing cost savings over the life of the Project?

A38. Yes. As mentioned above, timely cost recovery of the deferred costs through the ECCRA will reduce the overall balance of the regulatory asset as of the time it will be included in a subsequent base rate case thereby reducing the revenue requirement by $38.5 million over the life of the asset.[23] Timely cost recovery of amortization of the regulatory asset will result in gross financing cost savings over the life of the Project by providing the Company recovery of the costs earlier which reduces carrying charges over time.

Q39. Is AES Indiana proposing any changes to the DSM rate adjustment rider?

A39. No. AES Indiana is not proposing any new modifications to the language on Standard Contract Rider No. 22 in this proceeding. As discussed above, coincident with the approval of new rates in this proceeding, AES Indiana will cease the calculation and collection of lost revenues associated with all energy efficiency measures installed prior to the end of the Adjusted Test Year for which lost revenues were reflected in this proceeding. Accordingly, when new tariff sheets are filed based upon the final Order in this proceeding, AES Indiana proposes to adjust the then current DSM factors to reflect the removal of these lost revenues as of the same effective date. AES Indiana will then calculate and collect through the DSM rider, lost revenues for only the measures that were installed subsequent to the cutoff above, pursuant to approvals received in a future DSM Plan.

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[23] As shown on AES Indiana Witness KA Confidential Workpaper 1.

Q40. Is AES Indiana proposing any changes to the lost revenue calculation methodology?

A40. No. The methodology to calculate lost revenue will remain the same as the current approach described in each annual DSM rider proceeding. First, the number of installed measures for each program by rate, by month, will be determined. Next, the number of installed measures will be multiplied by the ex-ante estimates of kWh consumption and kW demand reductions per measure and net to gross ratios will be applied. This result is the estimated reduction in energy and demand for all DSM programs by rate. Finally, the total kWh and kW savings by rate will be multiplied by the lost revenue margin rates as reflected on AES Indiana Attachment KA-2. The updated lost revenue margin rates included in AES Indiana Attachment KA-2 are based upon the proposed tariffs and cost of service study sponsored by AES Indiana witness Rimal.[24]

In the Settlement Agreements approved in Cause Nos. 45370, 45898, and 46081, AES Indiana agreed to limit the time period for lost revenue recovery for the 2021 through 2026 DSM Programs as follows: (a) the life of the measure, (b) three years from implementation of any measure installed, or (c) until measure related energy savings are reflected in new base rates and charges, whichever occurs earlier.

Q41. Please explain the proposed modifications to the CAP rate adjustment rider.

A41. As discussed by AES Indiana witness Steiner,[25] AES Indiana proposes to reflect a forecasted level of capacity sales in the Adjusted Test Year revenue requirement (*see* AES Indiana Financial Exhibit AESI-OPER Schedule REV9). The Company is forecasting capacity sales rather than purchases as was the case in Cause No. 45911. The first

[24] AES Indiana witness Rimal, Direct Testimony, Q/A 27.
[25] AES Indiana witness Steiner, Direct Testimony, Q/A 27.

modification proposed for the language on the CAP rider is to change the references from "expense (or revenue)" to "revenue (or expense)" to reflect this shift. The second modification is to change the base amount used to calculate the CAP charge or credit on the tariff to $8.9 million of expected net capacity sales from the current benchmark of $19.0 million in capacity costs. These modifications have been reflected on the proposed Standard Contract Rider No. 24 (CAP) in AES Indiana witness Baker, Attachment AJB-1.

When new tariff sheets are filed after a final Order in this proceeding, AES Indiana proposes to adjust the then current CAP factors to reflect the new benchmark as of the effective date of this Order.

Q42. Please explain the proposed modifications to the OSS rate adjustment rider.

A42. As discussed by AES Indiana witness Steiner,[26] AES Indiana proposes to reflect a forecasted benchmark of $24.9 million for off-system sales margin in base rates of (*see* AES Indiana Financial Exhibit AESI-OPER, Schedule REV6).

When new tariff sheets are filed after a final Order in this proceeding, AES Indiana proposes to adjust the then current OSS margin factors to reflect the new benchmark as of the effective date of this Order.

Q43. Please explain the proposed modifications to the RTO rate adjustment rider.

A43. As discussed above, AES Indiana proposes to reflect forecasted benchmark of MISO non-fuel costs and revenues in base rates (*see* AES Indiana Financial Exhibit AESI-OPER, Schedules OM13 and REV8 respectively). AES Indiana proposes to modify the language

[26] AES Indiana witness Steiner, Direct Testimony, Q/A 21.

on the tariff for the RTO rider to change the benchmark amount of MISO non-fuel costs and revenues used to calculate the RTO charge or credit to $33.2 million and $3.6 million respectively.

Also, when new tariff sheets are filed after a final Order in this proceeding, AES Indiana proposes to adjust the then-current RTO Factors to reflect the new benchmark as of the effective date of this Order.

11. NEW RATE ADJUSTMENT RIDER

Q44. Is AES Indiana proposing the addition of any new rate adjustment riders?

A44. Yes. AES Indiana is proposing to add one new rate adjustment rider -- Property Tax Adjustment ("PTA"). AES Indiana witness Miller discusses how the annual property tax expense is material and experiences volatility. He further explains why an adjustment rider provides an efficient means to allow property tax changes to flow through to customers in a timely manner. The PTA factor is intended to recover the excess (or deficit) of an estimate of the property tax amounts compared to the amount of such costs approved to be included in the determination of basic rates in this proceeding as described further below.

This new rider is shown in AES Indiana Attachment AJB-1, page 178 as Standard Contract Rider 18.

Q45. Please provide additional details regarding the implementation of the proposed PTA Adjustment.

A45. AES Indiana witness Miller provides support for the $37.3 embedded in base rates for Property Tax.[27] AES Indiana proposes that the appropriate filing cadence for a revision of the PTA factor would be annually similar to several of the existing rate adjustment riders (RTO, DSM, ECCRA). AES Indiana proposes that the annual period run from January through December with a filing date in the third quarter and an effective date of January 1. The Company proposes to forecast the amount of annual property tax and defer the difference from actual until a subsequent annual rider filing. The estimated amount of PTA would be compared to the amount included in base rates in this proceeding and a true-up of the estimate to actual would occur in a subsequent annual filing. The estimated property tax amount would be allocated to each rate class based upon the demand allocators developed in the cost of service study sponsored by AES Indiana witness Rimal, and recovered from customers based on kWh billed.

12. PHASE-IN RATE ADJUSTMENT (“PRA”)

Q46. Please describe how the Company proposes to implement new base rates in this proceeding.

A46. As described by AES Indiana witness Peters, the Company’s proposed base rates in this proceeding are calculated using a forecasted rate base and revenue requirement for the Adjusted Test Year ending as of December 31, 2026. The Company proposes to implement the new base rate order in two phases to reasonably reflect rate base and revenue

[27] AES Indiana witness Miller Section 5, Table NM-1.

requirement updates at the time rates are placed into effect. The Phase-In Rate Adjustment ("PRA") credit described by AES Indiana witness Rimal is the mechanism that will be used to implement rates in two distinct steps and will be applied to Phase 2 rates in order to calculate Phase 1 rates.

The PRA will be eliminated at the end of the Test Year to reflect the second step of the phase-in. The Phase 2 rates will reflect the rate base and revenue requirement as of December 31, 2026 and adjust the Petersburg cost of labor to reflect the completion of the Repowering project.

The Company has also aligned the timing of its capital structure with net plant in service for purposes of developing the PRA rates.

Q47. Please summarize the steps of the phase-in rate implementation.

A47. The Company proposes to implement the PRA Phase 1 credit as part of the compliance filing following issuance of Commission order in this Cause. PRA Phase 2 will be implemented effective January 1, 2027. The proposed Phase 1 revenue increase is $85.4 million and the Phase 2 revenue increase is $107.5 million for a total incremental revenue increase of $192.9. I further discuss the PRA process below.

Q48. Please describe the adjustments made to calculate the PRA credit for Phase 1 rates?

A48. As shown in Table KA-2 below, the PRA credit calculation reflects changes to capital structure, rate base, certain O&M expenses and depreciation. These primary updates have a downstream effect on other schedules such as taxes, revenues and revenue requirement as also shown below.[28]

Table KA-2

AES Indiana Financial Exhibit:	Sponsoring Witness	Change	Downstream Impacts
AESI-CC, Schedule CC1	Illyes	Reflect Long-Term Debt balances as of 12/31/25	CC2
AESI-CC, Schedule CC2	Illyes	Reflect capital structure as of 12/31/25	REVREQ1
AESI-RB, Schedule RB2	Peters	Reflect Net Utility Plant in Service balance as of 12/31/25	RB1, DEPR, REVREQ1
AESI-RB, Schedule RB3	Aliff	Reflect accumulated depreciation as of 12/31/25	RB1, RB8, REVREQ1
AESI-RB, Schedule RB4	Aliff	Reflect accumulated depreciation as of 12/31/25	RB1, REVREQ1
AESI-RB, Schedule RB8	Aliff	Reflect regulatory asset balances as of 12/31/25	RB1, DEPR, REVREQ1
AESI-OPER, Schedule OM15	Dalton	Reflect additional headcount required before Petersburg repowering	OM16, OTX3, OTX1
AESI-OPER, Schedule DEPR	Peters	Reflect depreciation as of 12/31/25	RB1, REVREQ1
Downstream impacts of above changes			OPINC, REV1, REV10, OM1, OM25, OM26, TX1, TX2, TX3, TX4, TX6, TX8

Q49. Please describe the rate base updates made for Phase 1 rates.

A49. As shown on Table KA-2 above, AES Indiana proposes to update rate base to reflect forecasted net utility plant in service and accumulated depreciation as of December 31, 2025. These updates impact AES Indiana Financial Exhibit AESI-RB, Schedule RB2, RB3

[28] The title of "(P1)" is used on the Phase 1 financial schedules.

and RB4. A similar update is proposed for AES Indiana Financial Exhibit AESI-RB, Schedule RB8 to reflect the forecasted unamortized regulatory asset balances as of December 31, 2025.

Q50. Please describe the O&M updates made for Phase 1 rates.

A50. As shown on Table KA-2, AES Indiana proposes to update AES Indiana Financial Exhibit AESI-OPER, Schedule OM15 to reflect additional headcount necessary at Petersburg prior to the completion of the Repowering Project.

Q51. Please describe the remaining updates to schedules impacted for Phase 1 rates.

A51. The remaining primary updates are being made to AES Indiana Financial Exhibit AESI-OPER, Schedule DEPR to properly reflect forecasted depreciation and amortization expense as of December 31, 2025 and AES Indiana Financial Exhibit AESI-CC, Schedule CC1 and CC2 to align the Company's capital structure with the timing of rate implementation.

Q52. How will the Phase 1 rates be implemented?

A52. Similar to the Company's recent rate cases, AES Indiana will file a compliance filing shortly after the final Order is issued to reflect the Commission's findings, which will inform the approved PRA credit. Simultaneous with the implementation of the Test Year end rates based on the final Order, the PRA will reduce customer rates to effectively reflect rate base as identified above and cost of capital as of December 31, 2025 net of the labor adjustment, and depreciation and amortization adjustments as discussed above. This will reasonably reflect used and useful property as of the date of implementation and reasonably recognize the Test Year Petersburg headcount costs mentioned above. The Company would anticipate that Commission staff would review the tariff consistent with recent practice so that it may be placed into effect expeditiously and no more than 20 days after the Company files its compliance tariffs in this proceeding.

At the end of the Test Year, the PRA will be adjusted to zero such that the PRA in combination with AES Indiana's base rate charge will produce an overall rate that reflects the cost of service at the end of the Test Year, subject to the reconciliation process described below.

Q53. Please elaborate on how Phase 2 will be implemented.

A53. Following the end of the 2026 Test Year, the Company will make a compliance filing as soon as practicable. This compliance filing will reconcile the actual rate base and revenue requirement as of the end of the Test Year to the rate base and revenue requirement approved by the Commission's Order and replace the PRA Phase 1 credit.

The Company will certify its rate base at test-year end and calculate the resulting Phase 2 rates.[29] The Phase 2 rates will go into effect on the date that the Company makes this certification, or January 1, 2027, whichever is later. Rate base for Phase 2 rates will not exceed the lesser of (a) AES Indiana's forecasted test-year-end rate base, or (b) AES Indiana's certified test-year-end rate base. The OUCC and intervening parties will have 30 days from the date of certification to state any objections to AES Indiana's certified test-year-end rate base. If there are objections, the Company will be afforded an opportunity

[29] For purposes of this process, "certify" means the Company has determined it has completed the amount of rate base indicated in its certification and the corresponding net plant additions have been placed in service and are used and useful in providing utility service as of the date of certification. AES Indiana will serve all Parties with its certification.

to respond. Once the Commission decides the matter the Phase 2 rates will be trued-up (with carrying charges) retroactive to January 1, 2027.

Q54. Is this approach reasonable?

A54. Yes. As explained above, the PRA process will reasonably capture changes in utility investment as of the beginning and end of the Test Year as well as Test Year changes in operating costs at Petersburg.

13. SUMMARY AND RECOMMENDATIONS

Q55. Please summarize your testimony and recommendations.

A55. AES Indiana Financial Exhibit AESI-REVREQ, Schedule REVREQ1 fairly represents the Company's forecasted revenue requirement in this proceeding after taking into account adjustments as necessary to reflect certain Commission Orders, changes to rate base, regulatory assets, expenses, and revenues. The Company's proposal to implement rates through a PRA is reasonable and necessary and should be approved. The Company has sufficiently described the need to continue its existing riders, including various modifications to those riders and the addition of the new Property Tax Adjustment rider. Finally, the Company's request for alternative ratemaking treatment for the Petersburg Repowering Project through the ECCRA presents an overall cost saving alternative and should be approved.

Q56. Does that conclude your verified pre-filed direct testimony?

A56. Yes.

VERIFICATION

I, Kimberly Aliff, Revenue Requirements Manager for Indianapolis Power & Light Company d/b/a AES Indiana, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Kimberly Aliff
____
Kimberly Aliff
Dated: May 30, 2025

Summary of Regulatory Assets on Schedule

Regulatory Asset	Authorized in Cause No.	Forecasted Unamortized Balance as of May 31, 2026 Basis for Amortization Expense (Thousands)	Forecasted Unamortized Balance December 31, 2026 basis for Rate Base (Thousands)	Approved Amortization Period	Changes to Amortization Period
Petersburg Unit 4 costs and carrying charges*	39938	$264	$0	31 years	Amortize 5/31/26 balance over three years
Environmental Projects: NOx, MPP, MPP2, MATS , NPDES, HS7 carrying charges	42170, 44242, 43403	$7,506	$6,930	HS7 life of assets approved in 45029 All others 10 years approved in 45911	No change
Environmental Projects deferred depreciation	44242	$9,958	$9,141	10 years approved in 45911	No change
NAAQS-DBA depreciation	44794	$27	$25	10 years approved in 45911	No change
NAAQS-DBA post in-service AFUDC	44794	$54	$50	10 years approved in 45911	No change
CCR Bottom Ash depreciation	44794	$672	$623	10 years approved in 45911	No change
CCR Bottom Ash post in-service AFUDC	44794	$280	$260	10 years approved in 45911	No change
NAAQS-Other depreciation	44794	$350	$323	10 years approved in 45911	No change
NAAQS-Other post in-service AFUDC	44794	$268	$247	10 years approved in 45911	No change
Eagle Valley CCGT and Harding Street 5 & 6 depreciation	44339	$13,529	$13,040	Life of assets approved in 45029	No change
Eagle Valley CCGT and Harding Street 5 & 6 post in-service AFUDC	44339	$27,608	$26,650	Life of assets approved in 45029	No change
Electric vehicle Cause No. 44478*	44478	$262	$200	10 years approved in 45029	Amortize 5/31/26 balance over three years
HS7 Preservation Costs*	42170	$35	$0	10 years approved in 42170 ECR-26	Amortize 5/31/26 balance over three years
20% HS7 Gas Conversion savings revenue requirement	44540	($1,253)	($940)	Four years approved in 45911	Amortize 5/31/26 balance over three years
20% NPDES revenue requirement*	44540	$8,420	$6,315	Four years approved in 45911	Amortize 5/31/26 balance over three years
20% NAAQS-DBA revenue requirement*	44794	$419	$314	Four years approved in 45911	Amortize 5/31/26 balance over three years
20% CCR Bottom Ash revenue requirement*	44794	$929	$697	Four years approved in 45911	Amortize 5/31/26 balance over three years
20% NAAQS-Other revenue requirement*	44794	$2,003	$1,683	Four years approved in 45911	Amortize 5/31/26 balance over three years
Petersburg Unit 1 Retirement	45502	$21,172	$18,255	$5,000 per year	No change
Petersburg Unit 2 and Unit 1&2 shared assets	44502	$84,726	$77,976	10 years approved in 45911	No change
TDSIC deferred depreciation	45264	$19,775	$22,059	36.3 years	No change
TDSIC post in-service AFUDC	45264	$39,646	$45,230	36.3 years	No change
20% TDSIC Distribution revenue requirement*	45264	$26,994	$31,997	Four years approved in 45911	Amortize 5/31/26 balance over three years
20% TDSIC Transmission revenue requirement*	45264	$4,665	$5,622	Four years approved in 45911	Amortize 5/31/26 balance over three years

Indianapolis Power && Light Company d/b/a AES Indiana
DERIVATION OF LOST REVENUE MARGIN RATES

Rate Schedule	(1) Charge	(2) Units	(3) Applicable Block	(4) Basic Rates	(5) Less Base Fuel Costs	(6) Margin Rates (4) + (5)	(7) Less Variable O&M	(8) Lost Revenue Margin Rates (6)+(7)
					($0.450964)		($0.004710)	
Residential								
Rate RS: Residential Service (Non-space heating and water heating)	Energy	kWh	Tailblock	$0.148475	($0.045151)	$0.103324	($0.004715)	$0.098609
Rate RC: Residential w/ Electric Water Heating	Energy	kWh	Tailblock	$0.136061	($0.045151)	$0.090910	($0.004715)	$0.086195
Rate RH: Residential w/ Electric Space Heating	Energy	kWh	Tailblock	$0.136061	($0.045151)	$0.090910	($0.004715)	$0.086195
Rate ES: Residential Service (Non-space heating and water heating)	Energy	kWh	Tailblock	$0.133628	($0.045151)	$0.088477	($0.004715)	$0.083762
Rate EC: Residential w/ Electric Water Heating	Energy	kWh	Tailblock	$0.122455	($0.045151)	$0.077304	($0.004715)	$0.072589
Rate EH: Residential w/ Electric Space Heating	Energy	kWh	Tailblock	$0.122455	($0.045151)	$0.077304	($0.004715)	$0.072589
Small Commercial & Industrial								
Rate SS: Secondary Service (Small)	Energy	kWh	First Block	$0.154732	($0.045151)	$0.109581	($0.004759)	$0.104822
Rate SH: Secondary Service - Electric Space Conditioning	Energy	kWh	Uniform Rate	$0.160587	($0.045151)	$0.115436	($0.004752)	$0.110684
MD: Metered Municipal Device (Small)	Energy	kwh	Uniform Rate	$0.163956	($0.045151)		($0.004772)	
Large Commercial & Industrial								
Rate SL: Seconary Service (Large)	Energy	kWh	Uniform Rate	$0.058648	($0.045151)	$0.013497	($0.004747)	$0.008750
	Demand	kW	Uniform Rate	$28.13		$28.13		$28.130000
Rate PL: Primary Service (Large)	Energy	kWh	Uniform Rate	$0.055746	($0.045362)	$0.010384	($0.004760)	$0.005623
	Demand	kW	Uniform Rate	$33.10		$33.10		$33.100000
Rate PH: Process Heating	Energy	kWh	Tailblock	$0.118372	($0.045151)	$0.073221	($0.004758)	$0.068463
Rate HL-1: Primary Distribution Voltage	Energy	kWh	Uniform Rate	$0.054775	($0.045362)	$0.009413	($0.004760)	$0.004652
	Demand	kW	Uniform Rate	$34.30		$34.30		$34.300000
Rate HL-2: Subtransmission Voltage	Energy	kWh	Uniform Rate	$0.053437	($0.044473)	$0.008964	($0.004667)	$0.004297
	Demand	kW	Uniform Rate	$25.20		$25.20		$25.200000
Rate HL-3: Transmission Voltage (High Load Factor)	Energy	kWh	Uniform Rate	$0.052488	($0.044376)	$0.008112	($0.004657)	$0.003455
	Demand	kW	Uniform Rate	$25.00		$25.00		$25.000000
Rate HL-3: Transmission Voltage (Low Load Factor)	Energy	kWh	Uniform Rate	$0.080611	($0.044376)	$0.036235	($0.004657)	$0.031578
	Demand	kW	Uniform Rate	$16.08		$16.08		$16.080000