Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner			√

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA ("AES INDIANA") FOR AUTHORITY TO INCREASE RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, AND FOR APPROVAL OF RELATED RELIEF, INCLUDING (1) REVISED DEPRECIATION RATES, (2) ACCOUNTING RELIEF, INCLUDING DEFERRALS AND AMORTIZATIONS, (3) INCLUSION OF CAPITAL INVESTMENTS, (4) RATE ADJUSTMENT MECHANISM PROPOSALS, INCLUDING NEW ECONOMIC DEVELOPMENT RIDER, (5) REMOTE DISCONNECT/RECONNECT PROCESS, AND (6) NEW SCHEDULES OF RATES, RULES AND REGULATIONS FOR SERVICE	)	**CAUSE NO. 45911** **APPROVED: APR 17 2024**

ORDER OF THE COMMISSION

Presiding Officers:
Wesley R. Bennett, Commissioner
David E. Veleta, Commissioner
Greg S. Loyd, Administrative Law Judge

On June 28, 2023, Indianapolis Power & Light Company d/b/a AES Indiana ("Petitioner" or "AES Indiana") filed a Verified Petition with the Indiana Utility Regulatory Commission ("IURC" or "Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.[1] On June 28, 2023, Petitioner also filed its case-in-chief, workpapers, and information required by the minimum standard filing requirements set forth at 170 IAC 1-5.

The following witnesses provided testimony in support of AES Indiana's case-in-chief:[2]

- Kenneth J. Zagzebski, Senior Vice President, for AES Indiana and President, Utilities for AES US Services LLC ("AES Services").[3]
- Kimberly Aliff, Revenue Requirements Manager in Regulatory Affairs for AES Indiana.
- Austin J. Baker, Analyst II, Regulatory Affairs for AES Indiana.
- Vanessa Barbarisi, Director of Utility Transformation Strategy for AES Services.

[1] On May 26, 2023, AES Indiana provided its notice of intent to file a rate case in accordance with the Commission's General Administrative Order 2013-5.
[2] Corrections to AES Indiana's case-in-chief were filed on July 26, 2023, August 2, 2023, September 1, 8, and 19, 2023, and October 10, 2023.
[3] Mr. Zagzebski was substituted for and adopted testimony initially prefiled by Petitioner witness Kristina Lund.

- John Bigalbal, Chief Operating Officer, US Conventional Generation, AES Services.
- Chadwick M. Bocook, Director of Maintenance, Inspections, Contract Management and Reliability Programs for AES Services.
- Natalie Herr Coklow, Manager in Regulatory Accounting for AES Services.
- Matthew J. Dalton, Director of Human Resources for AES Services.
- Alexander J. Dickerson, Manager, Wholesale Energy for AES Indiana.
- Eric Fox, Director, Forecast Solutions for Itron, Inc.
- Paula M. Guletsky, Sargent & Lundy, L.L.C. Vice President and Project Director for AES Indiana.
- Michael L. Holtsclaw, Director of Power Transmission Field Operations for AES Indiana.
- Dustin J. Illyes, Treasurer of AES Services' US Utilities and Conventional Generation.
- Adrien M. McKenzie, President of Financial Concepts and Applications, Inc.
- Nicholas M. Miller, Senior Manager, Regulatory Tax for AES US Utilities and Conventional Generation, AES Services.
- Karin Nyhuis, Controller for AES US Utilities and US Conventional Generation, AES Services.[4]
- Bickey Rimal, Assistant Vice President for Concentric Energy Advisors, Inc.
- Hampton Matthew Roach, Senior Director, Benefits for AES Services.
- Brent A. Robinson, Senior Accountant for AES Services.
- John J. Spanos, President for Gannett Fleming Valuation and Rate Consultants, LLC.
- Jim Staton, Economic Development Lead for AES Services.
- Caleb Steiner, Director, Commercial Analytics & Strategy, US Utilities, AES Services.
- Lauren Whitehead, General & Operational Accounting Manager for AES Services.

Petitions to Intervene were filed by AES Indiana Industrial Group ("Industrial Group"), an ad hoc group of industrial customers;[5] Citizens Action Coalition of Indiana, Inc. ("CAC"); The Kroger Company ("Kroger"); Walmart, Inc.; Rolls-Royce Corporation ("Rolls-Royce"); and the City of Indianapolis, Indiana ("City"). The Presiding Officers granted each of these petitions without objection.

Public field hearings were held on August 24, 2023, and October 2, 2023, in Indianapolis, Indiana, the largest municipality in Petitioner's service area. At the field hearings, members of the public made statements to the Commission under oath.

On October 12, 2023, the OUCC and the above-named Intervenors filed their respective cases-in-chief. The OUCC provided testimony and attachments from the following witnesses:

- Michael D. Eckert, Director of the OUCC Electric Division.

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[4] Ms. Nyhuis was substituted for and adopted testimony initially prefiled by Petitioner's witness Robert Osborn.

[5] The Industrial Group consists of Allison Transmission, Inc., Eli Lilly and Company, Indiana University, Indiana University Health, Ingredion, Inc., Marathon Petroleum Company LP, and Messer LLC.

- Cynthia M. Armstrong, Assistant Director of the OUCC Electric Division.
- Brittany L. Baker, Utility Analyst in the OUCC Electric Division.
- Wes R. Blakley, OUCC Senior Utility Analyst.
- Leja D. Courter, OUCC Chief Technical Advisor.
- David E. Dismukes, Consulting Economist for Acadian Consulting Group.
- David J. Garrett, Managing Member, Public Utility Regulation Consultant for Resolve Utility Consulting, PLLC.
- John W. Hanks, Utility Analyst in the OUCC Electric Division.
- Kaleb G. Lantrip, Utility Analyst in the OUCC Electric Division.
- Brian R. Latham, Utility Analyst in the OUCC Electric Division.
- Derek J. Leader, OUCC Utility Analyst.
- April M. Paronish, Assistant Director of the OUCC Electric Division.
- Roopali Sanka, Utility Analyst in the OUCC Electric Division.
- Brian A. Wright, Utility Analyst II in the OUCC Electric Division.

The Industrial Group provided testimony and attachments from the following witnesses:

- Brian C. Andrews, Consultant and Associate, Brubaker & Associates, Inc.
- James R. Dauphinais, Consultant and a Managing Principal, Brubaker & Associates, Inc.
- Michael P. Gorman, Consultant and a Managing Principal, Brubaker & Associates, Inc.

CAC prefiled the testimony and attachments of Benjamin Inskeep, Program Director for CAC.

Kroger prefiled the testimony and attachments of Justin Bieber, Principal for Energy Strategies, LLC.

Walmart provided testimony and attachments from Steve W. Chriss, Senior Director, Utility Partnerships for Walmart, and Alex J. Kronauer, Senior Manager, Utility Partnerships for Walmart.

The City provided testimony and attachments from Ted Sommer, Certified Public Accountant for Sommer Consulting LLC.

On November 8, 2023, the OUCC filed the cross-answering testimony of David E. Dismukes, the Industrial Group filed the cross-answering testimony of James R. Dauphinais, and the CAC filed the cross-answering testimony of Benjamin Inskeep.

Also on November 8, 2023, AES Indiana filed rebuttal testimony, exhibits and workpapers for the following witnesses:

- Kimberly Aliff.
- Austin J. Baker.
- Vanessa Barbarisi.

- Chadwick M. Bocook.
- Natalie Herr Coklow.
- Pilar Cuadra, Environmental Manager in AES Global Environmental Affairs for AES Services.
- Matthew J. Dalton.
- Brandi Davis-Handy, Chief Customer Officer, US Utilities for AES Services.
- Alexander J. Dickerson.
- Alan D. Felsenthal, a Certified Public Accountant and a Managing Director at PricewaterhouseCoopers LLP.
- Paula M. Guletsky.
- Michael L. Holtsclaw.
- Adrien M. McKenzie.
- Nicholas M. Miller.
- Bickey Rimal.
- Brent A. Robinson.
- John J. Spanos.
- Jim Staton.
- Caleb Steiner.
- Lauren Whitehead.

On November 22, 2023, AES Indiana, on behalf of itself, OUCC, Industrial Group, CAC, Kroger, Walmart, Rolls-Royce, and City (collectively, "Setting Parties"), filed a Joint Motion for Leave to File Settlement Agreement and Request for Settlement Hearing ("Joint Motion"). The Joint Motion informed the Commission that the parties had executed the attached Stipulation and Settlement Agreement ("Settlement Agreement"), which resolved all issues pending before the Commission in this proceeding. By Docket Entry dated November 28, 2023, the procedural schedule was revised to allow presentation of evidence in favor of the settlement on November 29, 2023.

On November 29, 2023, AES Indiana prefiled Chad Rogers's settlement testimony and the OUCC prefiled Michael D. Eckert's settlement testimony.

The Commission issued a docket entry on December 14, 2023, requesting additional information from Petitioner, to which Petitioner responded on December 18, 2023.

The Commission conducted an evidentiary hearing in Room 222 of the PNC Center beginning at 1:30 p.m. on December 19, 2023. At the evidentiary hearing, the Settlement Agreement and each party's respective testimony and exhibits were admitted into the record without objection. The Commission questioned Petitioner Witness Rogers and OUCC witness Eckert during the hearing.

The Commission, based upon the applicable law and the evidence, finds as follows:

1. <u>Notice and Jurisdiction</u>. Due, legal and timely notice of all public hearings in this Cause were given and published as required by law. AES Indiana is a public utility as defined in Ind. Code § 8-1-2-1(a). Pursuant to Ind. Code §§ 8-1-2-42 and 8-1-2-42.7, the Commission has jurisdiction over AES Indiana's rates and charges for utility service. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **<u>Petitioner's Organization and Business</u>.** AES Indiana is a public utility with its principal place of business located at One Monument Circle, Indianapolis, Indiana. AES Indiana is part of The AES Corporation, a US-based energy company with global operations. AES Services is the service company that supports AES Indiana and other AES affiliates. AES Services is also headquartered in Indianapolis, Indiana.

AES Indiana provides retail electric utility service to approximately 519,000 retail customers located principally in and near the City of Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam, and Shelby Counties.

AES Indiana renders electric service by means of electric production, transmission and distribution plant, as well as general property, equipment and related facilities, including office buildings, service buildings, and other property, all of which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light, and power. AES Indiana's property is classified in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") and approved and adopted by this Commission.

AES Indiana is subject to the jurisdiction of FERC and is a member of the Midcontinent Independent System Operator, Inc. ("MISO"), a Regional Transmission Organization ("RTO") operated under the authority of FERC, which controls the use of AES Indiana's transmission system, as well as the dispatching of AES Indiana's generating units. As a member of MISO, charges and credits are billed to AES Indiana for functional operation of the transmission system, management of the MISO markets, and general administration of the RTO.

3. **<u>Existing Rates</u>.** AES Indiana's current basic rates and charges were approved by the Commission in its Order in Cause No. 45029, based upon test year operating results for the 12 months ended June 30, 2017, adjusted for fixed, known, and measurable changes. The petition initiating Cause No. 45029 was filed with the Commission on December 21, 2017. *Indianapolis Power & Light Company*, Cause No. 45029, 2018 WL 741643 *1 (IURC Oct. 31, 2018). Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than 15 months has passed between AES Indiana's last petition and the date AES Indiana filed its Petition in this Cause for a general increase in its basic rates and charges.

4. **<u>Test Year and Rate Base Cutoff</u>.** As authorized by Ind. Code § 8-1-2-42.7(d), the test period in the current Cause is the 12 months ended December 31, 2022 ("Test Year"), adjusted for fixed, known, and measurable changes and appropriate normalizations and annualizations. The Test Year end, December 31, 2022, is the general rate base cutoff date. The cutoff date for the Major Project identified in AES Indiana's Petition is November 24, 2023, as established by the Commission's July 24, 2023 Docket Entry.

5. <u>Relief Requested By AES Indiana</u>. In its Verified Petition filed in this proceeding, AES Indiana requested the Commission approve an overall annual increase in revenues of approximately $134 million, representing an overall increase of 8.92%. AES Indiana also requested Commission approval of specific accounting and ratemaking relief, including new depreciation accrual rates and modifications to rate adjustment mechanisms, and approval of its proposed revenue allocation and rate design.

6. <u>Opposition, Cross-Answer, and Rebuttal</u>. The OUCC and Intervenors presented numerous challenges to AES Indiana's evidence, including challenging rate base, return on equity ("ROE") and rate of return, operation and maintenance ("O&M") expenses, depreciation rates, rider proposals, cost of service allocation, vegetation management, AES storm preparation and response, and rate design. The extent to which these parties disagreed with each other was addressed in the parties' respective testimony and exhibits. In its rebuttal evidence, AES Indiana reduced the revenue deficiency to $122.9 million, which is an overall revenue increase of 8.36% and stated the extent to which Petitioner agreed or disagreed with the OUCC and Intervenors' positions.

7. <u>Settlement Agreement</u>. All parties of record in this Cause are signatories to the Settlement Agreement filed with the Commission on November 22, 2023, which resolves all pending issues in this Cause. The Settlement Agreement was admitted into the record as Joint Exhibit 1, is attached to this Order, and is incorporated by reference. The witnesses offering settlement testimony discussed the arm's-length nature of the negotiations and efforts undertaken to reach an uncontested and balanced settlement that fairly resolves all issues in the case. We discuss the terms of the Settlement Agreement and supporting evidence below.

Petitioner witness Rogers explained that, taken as a whole, the Settlement Agreement represents the result of arm's-length negotiations by a diverse group of stakeholders with differing views on the issues raised in this Cause. He testified that the Settling Parties' experts were involved with legal counsel in the development of both the conceptual framework and the details of the Settlement Agreement and that many hours were devoted by the Settling Parties to discussions, the collaborative exchange of information, and settlement negotiations. He contended the Settlement Agreement is in the public interest and reasonably resolves all issues in this docket without further expenditure of the time and resources of the Commission and the parties in the litigation of these matters.

Similarly, OUCC witness Eckert testified that the Settlement Agreement was the product of intense negotiation, with each party offering compromise on challenging issues. Mr. Eckert said the nature of the compromise included assessing the litigation risk associated with a contested hearing. He stated that, given the number of benefits provided to ratepayers, as outlined in the Settlement Agreement and described in his settlement testimony, the Settlement Agreement balances the interests of ratepayers and AES Indiana. He added that the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, supported by evidence, and should be approved.

Mr. Eckert testified the Settling Parties agreed to an annualized combined basic rate and rider revenue requirement increase of $72.9 million, an approximate $61.14 million reduction from AES Indiana's proposed basic rates revenue requirement increase of $134.2 million set forth in its case-in-chief. He stated that after the execution of the Settlement Agreement, the revenue requirement was further reduced by approximately $1.9 million due to the capital cost update for the AES Customer Ecosystem ("ACE") Project, for a total increase of approximately $71 million. Mr. Rogers stated, as a result of the Settlement Agreement and ACE Project capital cost update, the overall revenue increase from its current rate is 4.88%. Mr. Eckert testified the Settlement Agreement addresses the Five Pillars of Electricity Service outlined at Ind. Code §§ 8-1-2-0.5 and -0.6. Mr. Eckert explained residential electric customers will experience an overall bill increase of approximately $9.36 per month (7.2%), as opposed to the $17.49 increase (13.2%) AES Indiana proposed in its case-in-chief.

While these witnesses testified to the reasonableness of the settlement package as a whole, they also offered additional perspective on the terms of the Settlement Agreement as discussed below.

A. <u>Revenue Requirement</u>.

i. <u>ACE Project</u>. The ACE Project is a "Major Project" as defined in 170 IAC 1-5-1(l). Petitioner witness Vanessa Barbarisi explained the ACE Project creates a comprehensive customer information and data/operations management system to replace AES Indiana's customer information system developed in 1997. She summarized the 1997 system's shortcomings and the particular problems that indicate AES Indiana needs to modernize this system. She indicated AES Indiana's estimate of the utility's investment in the project to be $94 million.

The Industrial Group, OUCC, and CAC raised concerns about the ACE Project, which collectively included the project capital cost, annual O&M expenses, related "surge staffing," and including the remaining balance of the legacy system in rate base. Mr. Inskeep of the CAC contended AES Indiana did not articulate what meaningful benefits customers will receive from this project. He recommended the Commission carefully scrutinize the purported benefits of this project and weigh them against the real cost burden associated with the ACE Project and disallow cost recovery for any costs that are not reasonable or prudent.

The Settling Parties addressed this dispute through Section I.A.1.1 of the Settlement Agreement. This section sets forth the agreed-upon adjustments to the ACE Project related to legacy systems, which include removal of the $94,000 net book value legacy system assets from AES Indiana's rate base, as well as a reduction in O&M costs of $140,547.

Petitioner witness Rogers provided AES Indiana's November 2023 Monthly Major Project Investment Update for the ACE Project (admitted as Petitioner Exhibit 44, Attachment CAR-1S), the utility's final monthly investment update for this project. He testified that AES Indiana has updated the ACE Project capital cost to reflect a total capital cost of $83.9 million, as compared to $94.2 million presented in AES Indiana's case-in-chief. He noted this is a decrease of approximately $10.2 million to the agreed upon rate base. He also stated that while the Settlement

Agreement accepted the $94.2 million, AES Indiana has updated the agreed revenue requirement to reflect the updated ACE Project amount as of the cut-off date.

He explained the manner in which the updated ACE Project capital costs impacted the information set forth in the schedules attached to the Settlement Agreement as Attachments B through F. He sponsored updates to these attachments such that they reflect the Settlement Agreement terms and the final ACE Project capital costs; namely, Attachments CAR-2S (AES Indiana's Financial Exhibit Schedules), CAR-3S (agreed revenue allocation), CAR-4S (demand factors which will be utilized in AES Indiana's rate adjustment mechanisms after an Order in this Cause), CAR-5S (allocation factors), and CAR-6S (metered rates and lighting rates).

Mr. Rogers explained Section I.A.1.3 of the Settlement Agreement addresses the adjustment to amortization of non-recurring O&M and surge staffing to be amortized over four years, resulting in a reduction to O&M expense of $3.0 million; when combined with the removal of the legacy system O&M discussed above, the total is $3.2 million.

ii. <u>Amortizations and Rate Case Expense</u>. Schedule RB9 attached to Petitioner's Exhibit 45 set forth AES Indiana's originally proposed amortization periods for its regulatory assets. OUCC witness Blakely recommended the COVID-19 regulatory asset and the projects listed in Table 1 of his direct testimony be amortized over four years, which he said is the average length of AES Indiana's last two rate case Orders. Mr. Rogers explained that the Settling Parties incorporated this recommendation into Section I.A.2. This change reduces AES Indiana's related amortization expense from $35.9 million to $33.3 million.

Petitioner witness Robinson set forth the utility's $4,985,000 projected pro forma rate case expense estimate, to be amortized over three years. CAC witness Inskeep recommended the Commission deny this entire amount, arguing that included costs were unsubstantiated or unreasonable. Through Settlement Agreement Section I.A.2.3, the Settling Parties agreed upon a rate case expense of $3.0 million and that this expense will be amortized over four years.

iii. <u>Cost of Capital</u>. Sections I.A.3.1 through I.A.3.4 of the Settlement Agreement address three elements of capital costs: AES Indiana's ROE, the inclusion of AES Indiana's prepaid pension asset as part of its capital structure, and the rate of return on AES Indiana's original cost rate base.

a. <u>Return on Equity</u>. Petitioner witness McKenzie recommended an ROE of 10.6%, which he said would compensate Petitioner's investors, while maintaining Petitioner's financial integrity and ability to attract capital on reasonable terms. The OUCC and Intervenors provided testimony opposing AES Indiana's proposed ROE and recommended an ROE between 9.0% and 9.4%. The Settling Parties agreed in Settlement Agreement Section I.A.3.1 that AES Indiana's ROE will be 9.9%, which Mr. Rogers said is a reduction to the ROE that the Commission authorized in AES Indiana's last basic rate case and is within the range of evidence presented by the Settling Parties.

Mr. Eckert noted the 9.9% agreed upon ROE is also lower than the 10.6% ROE proposed as part of AES Indiana's case-in-chief. He said the 9.9% ROE more accurately reflects AES Indiana's risk profile than Petitioner's proposed 10.6% ROE. He further testified that the agreed reduction from Petitioner's requested ROE promotes affordability by reducing AES Indiana's requested return by $14.88 million. Mr. Eckert said the compromised rate of 9.9% is reasonable and in the interests of ratepayers while still preserving the financial integrity of AES Indiana.

b. **<u>Prepaid Pension Asset</u>.** Petitioner witness Roach testified that AES Indiana sought to include the full prepaid pension asset, net of the other postemployment benefits liability, of $166.2 million in the cost of capital calculation. The Industrial Group argued that the pension asset was not investor sourced and therefore should not be included in Petitioner's capital structure. Mr. Rogers stated Section I.A.3.2 of the Settlement Agreement reflects a compromise in which the Settling Parties agreed to lower the prepaid pension asset value by $35.1 million to $131.1 million.

c. **<u>Rate of Return</u>.** Petitioner initially proposed a capital structure that consisted of 49.52% long-term debt, 44.99% common equity, 0.81% customer deposits, (3.82%) prepaid pension asset, and 8.80% deferred income taxes. Petitioner also proposed a 10.6% cost of equity, which would result in a weighted average cost of capital ("WACC") of 7.22%. The OUCC advocated for a 9.1% cost of equity, which resulted in the OUCC recommending a WACC of 7.54%.

Through Section I.A.3.4 of the Settlement Agreement, and upon application of the 9.9% ROE and incorporating the $131.1 million prepaid pension asset discussed above, the Settling Parties agreed upon a WACC of 6.85%. Mr. Rogers provided the following table showing the agreed-upon capital structure and WACC:

Description	Total AES Indiana Capitalization (thousands of dollars)	Percent Of Total	Cost Rate	Weighted Cost Rate
Long-Term Debt	$ 2,153,036	49.15%	4.90%	2.41%
Preferred Stock	$ -	0.00%	0.00%	0.00%
Common Equity	$ 1,943,109	44.36%	9.90%	4.39%
Customer Deposits	$ 35,097	0.80%	6.00%	0.05%
Prepaid Pension Asset (net of OPEB liability)	$ (133,100)	(3.04)%	0.00%	0.00%
Deferred Income Taxes	$ 382,560	8.73%	0.00%	0.00%
Post 1970 ITC	$ 24	0.00%	7.28%	0.00%
Totals	$ 4,380,726	100.00%		6.85%

Combined with the reduced ACE Project value, this results in an agreed-upon net operating income of $235,972,000.

iv. <u>Depreciation Rates and Expense</u>. AES Indiana proposed a depreciation accrual amount of $225,043,786 based upon its use of the equal life group ("ELG") depreciation methodology. The OUCC recommended a $170,919,106 accrual amount and the Industrial Group recommended a $200,148,786 accrual amount based, in part, upon their use of the average life group ("ALG") methodology.

Mr. Rogers stated Section I.A.4 of the Settlement Agreement accepts the OUCC and Industrial Group's proposal to utilize the ALG methodology for depreciation rates. He said this change results in a reduction to depreciation expense of $24.8 million. Petitioner Exhibit 44, Attachment CAR-9S contains the depreciation rates calculated under the ALG procedure which the Commission is requested to approve. Mr. Eckert stated the reduction in depreciation expense using the agreed ALG methodology reduces the revenue increase, protecting affordability.

v. <u>IURC Fee and Revenue Conversion Factor</u>. AES Indiana initially proposed a public utility fee assessment factor of 0.1163% as part of its case-in-chief. AES Indiana and the OUCC agreed that this rate was subsequently changed to 0.1468%. Section I.A.5 of the Settlement Agreement provides that the IURC Fee rate of $0.001468 will be used to determine the IURC Fee and the revenue conversion factor for pro forma present and proposed rates as reflected in Attachment B to the Settlement Agreement.

vi. <u>Major Storms</u>.

a. <u>Major Storm Damage and Restoration Reserve and Major Storm Regulatory Liability</u>. In Cause No. 45029, the Commission approved the creation of a Major Storm Damage Restoration Reserve account. Petitioner witness Aliff said AES Indiana anticipated that, with no other major storm activity, as of December 31, 2023, there would be a credit balance of $6.1 million in the Major Storm Regulatory Liability account, which AES Indiana proposed to amortize over three years. In addition, AES Indiana proposed to continue recording one-twelfth of the $1.9 million average of the pro forma Level 3 & 4 storm expense as a monthly Major Storm Expense. Section I.A.6.1 of the Settlement Agreement reflects the Settling Parties' agreement to continue the Major Storm Damage and Restoration Reserve and to reflect the Major Storm Regulatory Liability account $6.1 million credit balance in rates. Mr. Eckert explained the continuation of the Major Storm Damage and Restoration Reserve addresses the problem for ratemaking that occurs because the timing, frequency, and amount of potential damage from major storms is unpredictable.

b. <u>Storm Damage Recovery Procedure and Response</u>. Mr. Eckert testified that storms on June 29, June 30, and July 2, 2023, impacted the AES Indiana service area. Mr. Eckert indicated that according to AES Indiana, the June 29 storm caused significant damage to AES Indiana's overhead distribution lines and caused 98,380 customers to lose service. He said the OUCC and CAC filed a Joint Petition for Commission Investigation ("Joint Petition") through which they requested the Commission open an investigation into AES Indiana's response to the June 29 storm. Mr. Eckert stated the Joint Petition remains pending in Cause No. 45917. In the current Cause, he raised concerns as to whether AES Indiana (1) requested assistance from all available storm restoration services, (2) properly notified its customers on a timely basis through appropriate communication methods, and (3) provided accurate information to the Commission about the situation. He reiterated the request set forth in the Joint Petition for an investigation into AES Indiana's storm response.

Mr. Eckert noted 170 IAC 4-1-23(b)(1) requires investor-owned utilities to report any unplanned interruption in service that lasts at least two hours and affects 2% or 5,000 customers (whichever is fewer). This regulation requires the utility to continue reporting on the outage until service has been restored to the lesser of 2% or 5,000 customers.

He stated the OUCC recommended lowering AES Indiana's 5,000 customer outage reporting threshold to 1,000. He also recommended Petitioner continue such reporting until the last customer is connected. He said such an approach would allow for a more accurate and comprehensive evaluation of future storm events by the Commission and the OUCC.

In rebuttal, AES Indiana witness Holtsclaw described AES Indiana's storm response. He said the company deployed 104 line crews, which is the most it had deployed for this level of storm in eight years. Mr. Holtsclaw noted other utilities were using mutual assistance to repair damage and that if AES Indiana had requested and received such assistance, this would have hampered repair work elsewhere. He explained why utility personnel believed they had sufficient crews to address the June 29 storm damage and therefore did not formally request mutual assistance. Mr. Holtsclaw also reviewed AES Indiana's storm communication plan and such communications relating to the June 29 storm specifically, as well as AES Indiana's outage reporting to the Commission.

Mr. Holtsclaw said AES Indiana agreed to lower its outage threshold to begin reporting from 5,000 customers to 1,000 customers. He stated AES Indiana disagreed with the OUCC that reporting should continue until electricity to the last customer has been restored; rather, he said AES Indiana proposed continuing to report until less than 1,000 customers remain without power.

Mr. Holtsclaw further testified on rebuttal that the investigation in Cause No. 45917 is not warranted nor needed. In support, he argued that AES Indiana's response to the June 29 storm was equal to or better than the response provided by other utilities, as evidenced by a comparison of storm response information other utilities provided at a September 28, 2023 technical conference regarding their respective response. In particular, he noted that the priorities used to guide each utility's overall restoration efforts were the same. He stated there was no justification why any one of these utilities should be singled out for investigation.

Through Settlement Agreement Section I.A.6.2, the Settling Parties agreed to lower the threshold for AES Indiana to begin its 170 IAC 4-1-23(b)(1) reporting to 2,500 customers and for the utility to continue reporting on these outages until its customer interruptions drop to zero customers. Through the Settlement Agreement, AES Indiana agreed to meet with the OUCC and other interested Settling Parties to collaborate on any additional modifications to AES Indiana's storm reporting requirements and/or related procedures and will a submit a report under this Cause of any resulting recommendations to the Commission within 90 days of a Commission Order approving this Settlement Agreement.

vii. <u>Non-Outage O&M</u>. AES Indiana initially proposed to adjust non-outage generation test year O&M by removing $1.3 million related to the Eagle Valley extended outage, pursuant to the Cause No. 38703 FAC 133 S1 Settlement Agreement, and $12.2 million for the Petersburg Unit 2 actual costs because the unit is now retired. OUCC witness Cynthia Armstrong agreed with AES Indiana's rationale for removing these costs. Mr. Rogers explained the Settling Parties agreed to the Non-Outage O&M expense as proposed in Petitioner's Exhibit 45, Schedule OM-7.

viii. <u>Other Operating Expense Adjustments</u>. Petitioner's Exhibit 45, AES Indiana Financial Exhibit AESI-OPER, Schedules OM1, OM6, OM9, OM22, and OM26, detail certain expenses that were included in AES Indiana's pro forma adjustments. CAC witness Inskeep argued against the inclusion of trade, social, service membership association dues, charitable and civic contributions, and expenses for the utility's sponsorship and promotional advertising, totaling approximately $1.1 million.

Mr. Rogers stated Section I.A.8 of the Settlement Agreement reduces operating expenses from AES Indiana's original proposal by $2.3 million to reflect a negotiated compromise of disputed operating expense issues, including, but not limited to, CAC witness Inskeep's testimony regarding membership costs. This adjustment is reflected in Joint Exhibit 1, CAR-2S, Schedule OM22-S-R. Mr. Eckert stated the adjustments to Other Operating Expense promote affordability and reduce AES Indiana's requested revenue requirement.

ix. <u>Payroll Expenses</u>. AES Indiana proposed in its case-in-chief to increase its payroll expense by $17,716,000 for increased payroll rates, compensation, and AES Services charges. OUCC witness Latham disputed AES Indiana's assumptions and calculations to determine its payroll increases and recommended a $1,644,376 payroll expense adjustment.

Section I.A.9 of the Settlement Agreement lowers AES Indiana's Wage Expense and Payroll Tax Expense by $3.8 million. This reduction is reflected in Joint Exhibit 1, Attachment CAR 2-S, Schedules OM15-S-R (lines 1 and 2) and Schedule OTX3-S-R (lines 1 and 2). He asserted this term is within the range of competing evidence presented on this issue. Mr. Eckert testified the agreed reduction in payroll expenses will benefit ratepayers and is in the public interest.

x. <u>Petersburg Units 1 and 2 Regulatory Asset</u>. Petersburg Units 1 and 2 were retired in May 2021 and May 2023, respectively. The Commission, through its November 17, 2021 Order in Cause No. 45502, permitted AES Indiana to record regulatory assets for these units. Through that Order, the Commission also authorized AES Indiana to recover the unamortized balance in its next rate case. AES Indiana proposed a combined regulatory asset balance of $287.4 million for these units and to use a declining balance recovery methodology to recover the Petersburg regulatory asset. Industrial Group witness Gorman argued that AES Indiana overstated the unrecovered balances of the regulatory assets and recommended a $9.2 million reduction in the regulatory asset balance to $278.2 million. He also argued in favor of a levelized asset recovery procedure, instead of a declining balance methodology. Mr. Gorman also recommended an adjustment of the regulatory asset to reflect the continued build-up of accumulated depreciation and reduction to the net book value of these units and recovery of depreciation expense for Petersburg Units 1 and 2 that is built into current rates, until the time the rates established in this proceeding take effect.

Section I.A.10 of the Settlement Agreement reflects the Settling Parties' resolution to these issues. Messrs. Rogers and Eckert said the Settling Parties agreed to reduce the regulatory asset balance for Units 1 and 2 by $4.152 million. Mr. Rogers said pursuant to Section I.A.10.2, these regulatory assets will be amortized through the revenue requirement as proposed by AES Indiana. The adjustments to Petersburg Units 1 and 2 rate base and amortization are reflected on Joint Exhibit 1, Attachment CAR-2S, Schedule RB-9S-R, Page 3, Lines 21 and 22.

xi. **Materials and Supplies.** AES Indiana proposed to remove 100% of seasonal nitrogen oxide ("NOx") allowance expense ($0.9 million) from the test year and to track any future seasonal NOx allowance purchases or sales through the environmental compliance cost recovery adjustment. OUCC witness Armstrong agreed with AES Indiana's proposal to remove this expense because (1) AES Indiana's seasonal NOx emissions are likely to be lower than the zero cost allowances allocated to its generating units annually and (2) AES Indiana's annual emissions should decrease further as the Petersburg coal units are retired or converted to natural gas.

Section I.A.11 of the Settlement Agreement adopted AES Indiana's proposal to remove the NOx allowance expense and to remove the associated emission allowance inventory of $648,000 from the test year Materials and Supplies balance. This decrease is reflected in Joint Exhibit 1, Attachment CAR-2S, Schedule RB7-S-R (lines 1 through 14).

xii. **Remote Disconnect/Reconnect/Billing Format.** Petitioner witness Baker testified that AES Indiana proposed to remotely disconnect and reconnect customers using its advanced metering infrastructure ("AMI"). Under this proposal, AES Indiana would utilize phone calls, text, or email messages to communicate final disconnect notices to residential customers instead of conducting an in-person, on-premises visit. OUCC witness Paronish raised concerns that some customers may not receive sufficient notice of an impending disconnection. CAC witness Inskeep raised issues about the impact of the proposal, particularly upon medically vulnerable customers. Ms. Paronish and Mr. Inskeep each described certain recommendations to address their respective concerns.

Section I.A.12 includes terms setting forth an agreed-upon method for AES Indiana to notify its customers about the importance of maintaining current contact information and to inform its customers about the remote disconnect/reconnect program. The agreement designates the particular language AES Indiana is to use for such communications. The Settlement Agreement also lengthens the medical disconnection protection time for LIHEAP Qualified Participants who have a Medical Hold or a Medical Alert. The agreement also requires AES Indiana to offer to meet with the CAC and OUCC to collaborate regarding customer education/outreach and Petitioner's procedures regarding the Medical Alert and Medical Hold Programs. Mr. Eckert testified the requirements in the Settlement Agreement will increase customer notifications with respect to the proposed remote disconnect and reconnect procedures.

AES Indiana will be required under the Settlement Agreement to perform an on-premises visit on the day of disconnect for customers in the Medical Alert and Medical Hold program, participants of the AMI opt-out program, customers who otherwise do not have an AMI meter, or customers who have not provided a phone number or email address.

Settlement Agreement Section I.A.12.5 prohibits AES Indiana from disconnecting service for any residential customer on Fridays, Saturdays, Sundays, and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Friday after Thanksgiving Day, December 24, and Christmas Day.

The Settlement Agreement also sets the fee for remote disconnection at zero dollars and the fee for remote reconnection at three dollars. The Settlement Agreement also states that AES Indiana will waive, once in a rolling 12-month period, the manual disconnection and manual or remote reconnection fees of a LIHEAP Qualified Participant.

xiii. Riders.

a. Environmental Cost Recovery Rider. AES Indiana initially proposed an $18.4 million benchmark (the average of the annual forecasted consumable cost for 2023 and 2024) for ammonia, coal combustion products, limestone and other chemicals attributable to retail sales that are included in the test year expense. OUCC witness Armstrong recommended reducing AES Indiana's proposed consumables cost to $15.523 million by excluding 2023 forecasted consumables attributed to Petersburg Unit 2 operations due to the unit's retirement. Mr. Steiner stated in rebuttal that AES Indiana agreed to Ms. Armstrong's recommendation.

CAC witness Inskeep noted that AES Indiana included coal ash as a consumable. He opposed AES Indiana's proposal to dispose of a confidentially designated amount of coal ash in coal mines because he said this manner of disposal may not adequately protect human health and the environment. As such, he recommended the Commission disallow all costs associated with disposing coal ash at any coal mine that does not permanently and safely store the coal ash in a manner that would prevent leaching and contamination of toxic coal ash.

The Settling Parties agreed through Section I.A.13.2 to remove test year emissions allowance costs and to track these costs through the environmental cost recovery rider. The Settling Parties further agreed through Section I.A.13.1 to lower consumables costs embedded in base rate revenue requirement by $2.9 million. Mr. Rogers said this is consistent with the testimony of OUCC witness Armstrong.

b. Economic Development. Petitioner proposed the establishment of Rider 27, which would provide a temporary reduction in its AES Indiana charges to large commercial and industrial ("C&I") customers (specifically, those receiving service from the company under Rates SL, PL, PH, and HL) who bring material economic development to AES Indiana's service territory. The purpose of the Rider is to improve AES Indiana's competitiveness in supporting economic development and encouraging growth in the communities the utility serves.

No party opposed the establishment of this Rider, but Industrial Group witness Dauphinais recommended Petitioner prepare and present a definitive mechanism for calculating the discount for participating customers. Similarly, the OUCC recommended AES Indiana develop a policy guide to inform its decisions regarding the Rider. The OUCC also recommended AES Indiana provide annual reports to the Commission and OUCC documenting the rider's cost-effectiveness, the names and business sectors of the customers utilizing the rider, and the provided incentive amounts.

Through Section I.A.13.2, the Settling Parties agreed to AES Indiana's proposed Economic Development Rider, subject to the requirement that prior to implementation, AES Indiana provide the OUCC and CAC a copy of its internal policy manual outlining the criteria that will be used to determine the discount for qualifying customers consistent with the Evaluation Criteria in the Economic Development Rider included as part of Petitioner Exhibit 4, Attachment AJB-2. Further, AES Indiana agreed to report annually to the Commission, OUCC, and CAC the name of customers receiving service under the Economic Development Rider, and the provided incentive amount, subject to the protection of confidential information from disclosure.

c. Fuel Adjustment Clause ("FAC"). AES Indiana initially proposed that its base cost of fuel be set at $0.041479 per kilowatt hour ("kWh"). Mr. Eckert testified that this cost of fuel was too high given market conditions. He explained his rationale that the base cost of fuel should be set at $0.039027 per kWh, a calculation that AES Indiana accepted through its rebuttal testimony. Through Section I.A.13.3, the Settling Parties adopted the $0.039027 per kWh base cost of fuel. This update reflects a fuel cost reduction of approximately $31.9 million compared to Petitioner's direct testimony, which results in a decrease to Petitioner's revenue requirement of $32.099 million.

The Settling Parties, through Section 13.3.3. of the Settlement Agreement, extended the agreement between AES Indiana and the OUCC in which the OUCC and Intervenors in FAC cases are to file their testimony and report within 35 days of AES Indiana filing its application and testimony. Mr. Eckert explained that a 35-day review period is necessary to provide the OUCC with adequate time to review AES Indiana's quarterly FAC filings and issue appropriate discovery to evaluate and address issues, as needed. He said the OUCC has 35-day agreements with all five Indiana investor-owned electric utilities in their respective FAC proceedings.

d. Lakefield Purchase Power Agreement. Mr. Rogers explained that through Section I.A.13.3.2, the Settling Parties agreed to AES Indiana's proposal to move the Lakefield Purchase Power Agreement adjustment from the utility's FAC to its Off-System Sales ("OSS") Rider. He explained that once this transition is accomplished, all OSS margins will be reflected in the OSS Rider, which would simplify the OSS and FAC calculations. OUCC witness Eckert did not oppose this change.

e. Off-System Sales, Capacity, and Regional Transmission Organization Riders. Mr. Rogers stated Settlement Agreement Sections I.A.13.4.1 through I.A.13.4.3 adopt AES Indiana's proposals regarding its Off-System Sales, Capacity, and Regional Transmission Organization Riders. These proposals, all of which the OUCC supported, included:

- A $28.6 million benchmark for AES Indiana's Off-System Sales Margin in Rider 26 based upon the five-year historical average annual MWh attributable to OSS as the sales quantity and a forward looking $/MWh margin to value the OSS MWh;
- An increase to AES Indiana's capacity cost benchmark embedded in basic rates to $19 million due to significant changes in the MISO capacity construct and accreditation methodology; and
- A change to the base amount of AES Indiana's MISO non-fuel costs and revenues used to calculate the RTO charge or credit to $35.8 million and $3.6 million, respectively.

f. <u>Interruptible Demand Response</u>. AES Indiana has five interruptible tariff riders, three of which are unused (Riders 15, 18, and 23) and the other two only have a handful of participants (Riders 14 and 17). AES Indiana proposed to consolidate all of these Riders into a new, general offering—Interruptible Demand Response (Rider 19), which would serve as a mechanism for AES Indiana to enter into interruptible demand response contracts with customers with at least 100 kilowatts ("kW") of interruptible demand. CAC witness Inskeep raised three issues regarding AES Indiana's proposal: (1) the lack of a stated rate or amount per kilowatt payment to customers for participation in Rider 19; (2) the eligibility for aggregation; and (3) the potential for additional unknown programmatic requirements or conditions that may deter participation.

In Section I.A.13.5, the Settling Parties agreed to approval of the utility's proposed Rider 19, modified to expand customer class eligibility to include rates PH, SH, and SS and to allow aggregation of smaller commercial customers with demand less than the 100 kW minimum. The agreement further provides that AES Indiana will collaborate with the Demand-Side Management ("DSM") Oversight Board on adding a minimum dollar per kilowatt value for the rate in Rider 19 and expanding terms and conditions of participation as part of the next DSM Plan. Messrs. Rogers and Eckert explained that while rate RS will not be included in Rider 19 as part of this Settlement, AES Indiana will continue to include a residential demand response aggregation program proposal for rate RS customers so that these customers may participate in Rider 19 in the broader Request for Proposals that AES Indiana is working to issue in 2023 to facilitate development of its next DSM Plan. Messrs. Rogers and Eckert explained that to the extent the DSM Oversight Board finds adding rate RS to Rider 19 is a viable option, in AES Indiana's DSM Plan proceeding to be initiated in 2024, AES Indiana will report on this collaboration, present recommendations, and Rider 19 will be updated as necessary as part of that proceeding.

xiv. <u>AES Services Agreement</u>. AES Services provides accounting, legal, human resources, information technology, supply chain, physical security, and other similar services to AES Indiana. AES Indiana compensates AES Services for the costs required to provide this work. AES Services billed AES Indiana $5.8 million during the test year for these services. OUCC witness Lantrip recommended the Commission approve these costs, subject to the requirement that Petitioner update the Commission and OUCC as to the status of the service agreement remaining in place beyond the beginning of January 2024.

Through Section I.A.14, the Settling Parties agreed AES Indiana's Adjustment OM23, subject to the requirement that AES Indiana update the Commission and Settling Parties on the status of the service agreement remaining in place beyond the beginning of January 2024. Mr. Rogers stated in his settlement testimony that the extended service agreement was filed with the Commission on November 28, 2023.

xv. **__Vegetation Management__.** AES Indiana witness Bocook stated vegetation is the single leading cause of outages at AES Indiana. AES Indiana proposed a pro forma adjustment to vegetation management cost in the amount of $10.2 million, increasing these costs to $25.2 million. He said this increase is driven primarily by increases in contractor labor costs, AES Indiana's plan to remove overhanging vegetation for a 15-foot box specification, and an increase in the number of miles each year for circuit maintenance such that the company would annually perform maintenance on approximately a quarter of its total overhead line miles. An AES Indiana study of its 2022 trimming practices showed that removing overhang vegetation reduced interrupted customer minutes by 20%, as compared to a 15-foot box trim, viewed one year after each trim.

The OUCC, Industrial Group, and CAC offered testimony that AES Indiana's proposed pro forma adjustment was excessive. The OUCC recommended a pro forma adjustment of $3,858,427, for a total pro forma distribution expense of $18,891,120. The Industrial Group recommended that the vegetation management reserve be set to a level above the 2022 test year that reflects a 5.0% escalation to account for inflation and other cost increases. He stated this adjustment lowers Petitioner's proposed revenue requirement by approximately $8.7 million.

The Settling Parties agreed, through Section I.A.15 of the Settlement Agreement, to embed $25 million in basic rates for vegetation management and continue the mechanism established in Cause No. 45029 to address any cumulative shortfall in annual expenditures for vegetation management costs on AES Indiana's distribution facilities relative to the amount embedded in basic rates. Any such shortfall will be deferred. That deferral mechanism serves as a cap and no amounts spent above the amount embedded in base rates on a cumulative basis will be deferred. In AES Indiana's subsequent base rate case, any balance in the established and continued regulatory liability will be amortized into the cost of service as a credit to the retail revenue requirement.

Mr. Rogers stated this provision supports Petitioner's ongoing effort to address the vegetation management plan and maintain or advance service reliability. Mr. Eckert testified that AES Indiana's proposed Vegetation Management Program and the associated proposed Vegetation Management expense amount of $25 million is one aspect of the Settlement Agreement that will address the reliability, resiliency, and stability pillars of Ind. Code § 8-1-2-0.6.

xvi. **__Additional Points__.** Mr. Rogers stated the terms of Section I.A.16 addresses rate implementation, interest synchronization, and revenue requirement matters not addressed elsewhere. The Settlement Agreement provides that AES Indiana will provide $50,000 in 2024 to help fund the Power of Change Program and the Indiana Community Action Association. The Settlement Agreement provides that AES Indiana's revenue deficiency will not be adjusted to include this contribution.

B. Cost of Service, Rate Design, and Other Issues.

i. Residential Customer Charge. AES Indiana proposed to increase its monthly residential charge for small customers (customers using less than 325 kWh/month) from $12.31 to $16.50 and for large customers (customers using more than 325 kWh/month) from $16.75 to $25.00. OUCC witness Dismukes provided his residential customer charge recommendation in Attachment DED-13 to Public's Exhibit 12. Mr. Inskeep of the CAC recommended that the Commission limit the customer charge increase to $13.22 and replace the current residential volumetric declining block rates by a flat variable charge.

Mr. Rogers stated Section I.B.l of the Settlement Agreement presents the agreed-upon residential fixed, monthly customer charges. Mr. Eckert provided the following comparison of the current residential customer charge, the charge amount proposed in AES Indiana's case-in-chief, and the agreed upon charge:

Customer Charge Description	Current Customer Charge	AES Indiana Proposed Customer Charge	Settled Customer Charge
Bills of 0-325 kWh/month	$12.31	$16.50	$12.50
Bills Over 325 kWh/month	$16.75	$25.00	$17.00

Mr. Rogers said these increases return the respective rates to the amounts originally approved in Cause No. 45029 as the originally approved amounts had been decreased to reflect the removal of the utility receipts tax.

ii. Declining Block Rate. Petitioner witness Bickey Rimal testified that AES Indiana's proposed rates included the existing declining-block rate structure for residential and small commercial customers. Ms. Rimal testified that the rates per kWh for the residential (RS) class are higher for the first 500 kWh and lower for amounts over 500 kWh. She added that residential water heating (RC) and space heating (RH) customers also are eligible for a lower third block for consumption over 1,000 kWh in a month. Ms. Rimal explained that small commercial (SS) customers will be charged a higher rate for the first 5,000 kWh consumed each month and a lower rate will be charged for amounts over 5,000 kWh. Ms. Rimal and CAC witness Inskeep disagreed on whether demand-related costs are appropriately recovered through declining volumetric rates.

Mr. Rogers stated Section I.B.2 addresses the agreed-upon adjustment to Petitioner's declining block energy rates. The Settlement Agreement provides the following:

kWh	AES Initial Proposal	Settlement
First 500 kWh per month	$0.132688	$0.125583
Over 500 kWh per month	$0.117223	$0.113985
With electric heating and/or water heating over 1000 kWh	$0.104809	$0.101571

Mr. Rogers contended this provision is consistent with the testimony of Petitioner witness Rimal and reasonably addresses concerns raised by the CAC and OUCC regarding the fixed customer charge.

iii. Residential Late Payment Charge. CAC witness Inskeep argued that AES Indiana should eliminate or reduce its late payment charge based on affordability concerns. Petitioner witness Baker testified the CAC's recommendation does not take into account cost-causation principles with respect to disconnection and reconnection charges. Mr. Rogers and Mr. Eckert explained Section I.B.3 of the Settlement Agreement provides that once in a rolling 12-month period, Petitioner will waive the late payment charge on a delinquent bill, provided payment is tendered no later than the last date for payment of the net amount in the next month's bill. Both witnesses indicated this is one of several provisions agreed upon as part of the settlement package to benefit residential customers.

iv. LIHEAP Customer Deposit. Based on affordability concerns, CAC witness Inskeep recommended AES Indiana reduce its security deposit for LIHEAP customers to $50. Mr. Rogers and Mr. Eckert explained Section I.B.4 of the Settlement Agreement limits deposits for residential service and deposits for current customers who are LIHEAP Qualified Participants to $50.

v. Excess Distributed Generation Reporting. Mr. Inskeep testified that AES Indiana is not currently required to identify the monthly additions of the number of customers and capacity by type of customer (residential vs. non-residential) participating in the company's Excess Distributed Generation tariff or Small Power Production tariff. Mr. Inskeep said that without adequate data, it is not possible to understand critical trends in customer adoption of distributed generation or basic information such as the total number of participating customers and capacity.

Section I.B.5 of the Settlement Agreement provides that AES Indiana will provide certain additional data as part of the annual performance metrics reporting in Cause Nos. 44576 and 44602. Specifically, AES Indiana agreed to provide data on Excess Distributed Generation tariff and Small Power Production tariff customer participation, broken down by residential and non-residential customers, and include data on both new and total (1) capacity (kW-ac) installed, (2) number of customers, and (3) size of battery storage system (both kW and kWh) if one is part of the customer's system and that detail is provided to AES Indiana by the customer.

vi. Multi-Family Data Collection. CAC witness Inskeep raised concerns about including multi-family residential customers and single-family residential customers in the same rate class. Settlement Agreement Section I.B.6 provides that AES Indiana is to collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. This section also states that AES Indiana will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, AES Indiana will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested Settling Party with the results of its analysis.

vii. Revenue Allocation. Mr. Rogers explained that Section I.B.7.1 of the Settlement Agreement sets forth the Settling Parties' agreement regarding allocation of the revenue requirement. He said Section I.B.7.2 also provides the agreed TDSIC allocation factors. He added that the allocations agreed to in this Section are detailed in Settlement Agreement Attachment C (revenue allocation), Settlement Agreement Attachment D (demand allocators), and Settlement Agreement Attachment E (distribution and transmission costs allocation percentages). He said the Settling Parties agreed that the allocations presented in Settlement Agreement Attachment E, as revised in Attachment CAR-5S, represent the "customer class revenue allocation factors" based on firm load with interruptible load removed as required by Ind. Code § 8-1-39-9(a)(l).

According to Mr. Eckert, the OUCC views the task of revenue allocation as one of ensuring that any cost increases are fair and reasonable to all rate classes. He stated the Settling Parties spent considerable time negotiating a fair and reasonable revenue allocation among all rate classes. The OUCC concluded the agreed revenue allocation is a fair compromise in the context of the overall Settlement Agreement.

Messrs. Rogers and Eckert testified that the agreed-upon revenue requirement allocations were determined strictly for settlement purposes and are without reference to any particular, specific cost allocation methodology.

viii. Rate Design, Cost of Service and Other Issues. OUCC witness Eckert explained that the Settlement Agreement limits the impact to a residential customer using 1,000 kWh per month to an increase of 7.2%, compared to AES Indiana's initial proposal that would have increased the same residential customer's monthly bill by 13.2%. Petitioner witness Rogers noted that comparing a residential customer's $139.36 bill for 1,000 kWh to the Commission Staff's July 1, 2023 jurisdictional residential bill survey (excerpt admitted as Attachment CAR-7S to Petitioner's Exhibit 44) indicates AES Indiana's rate would be the second lowest of Indiana's investor-owned utilities and lower than the state investor-owned electric utilities' average.

AES Indiana and the Industrial Group disagreed as to the extent to which the utility's low-load factor analysis complied with the requirement set forth in the Commission's Order in 45029 to conduct such an analysis. Industrial Group witness Dauphinais proposed that the Commission require AES Indiana to again work with the Industrial Group and other interested parties to develop a true low load factor customer rate that will work for a broader group of Rate PL and Rate HL customers. He also recommended the Commission require Petitioner to develop a plan to implement this rate such that any subsidies being paid by members of the new rate class under current rates are substantially reduced.

Mr. Rogers testified that Section I.B.8 of the Settlement Agreement reflects an agreement for Petitioner to discuss the creation of a low load factor rate with Kroger, Walmart, Rolls-Royce, and the Industrial Group, prior to filing its next basic rate case. He said Petitioner agrees to prepare a low load factor analysis, provide this analysis to the Settling Parties, and seek input on eligibility criteria and other related issues in a timely manner sufficient to afford the Settling Parties a reasonable opportunity to provide meaningful input prior to filing its next basic rate case. He said the Settling Parties further agree that AES Indiana is not obligated to propose a low load factor rate or take a position in support of or against any such rate structure in its next basic rate case and that all Settling Parties, including AES Indiana, will have the opportunity to take any position with respect to the aforementioned analysis as they deem appropriate in the next basic rate case and each reserves the right to present its own alternative analysis and proposal.

ix. Other Customer Charges Pro Forma Adjustment. Mr. Rogers explained that Section I.B.9 of the Settlement Agreement reflects the Settling Parties' negotiated compromise to include a $1.0 million pro forma adjustment to reduce the Residential revenues portion of total sales of electric energy, which is reflected on Joint Exhibit 1, Attachment CAR-2S, Schedule REV10-S-R, Line 10.

x. City of Indianapolis. Section I.B.10 of the Settlement Agreement addresses the following issues particular to the City of Indianapolis: streetlight rates, light emitting diode ("LED") light change out, relocation, and agreed future discussions.

a. Tariff MU-1 Rates. AES Indiana's stated proposed increase to its street lighting tariff was 9.01%. City of Indianapolis witness Sommer recommended an increase to this tariff be no greater than any increase the Commission finds appropriate for the residential customer. Section I.B.10.1 of the Settlement Agreement provides that the rates for Tariff MU-1 customers shall be as set forth in Settlement Agreement Attachment F. Mr. Rogers stated in his settlement testimony that AES Indiana adjusted these rates to reflect the reduction in ACE Project capital costs.

b. LED Lighting. City witness Sommer recommended that AES Indiana develop a comprehensive long-term plan, with stakeholder input, regarding AES Indiana converting the utility-owned streetlights that use all-purpose lights and vintage lights to lights that use LED lights. Mr. Rogers stated Section I.B.10.2 imposes a requirement for AES Indiana to analyze and develop a written report regarding the conversion of certain lighting with LED lights of comparable illumination with input from the City, other street-lighting customers, and other interested Settling Parties on this analysis.

c. Relocation. Mr. Rogers stated Section I.B.10.4 of the Settlement Agreement provides that when certain streetlights are to be relocated for a capital improvement project, such streetlights shall not be considered "new construction" if the existing facilities are re-used in the new location.

d. Future Discussions. Mr. Rogers explained Section I.B.10.5 sets a requirement for Petitioner and the City to discuss certain issues relating to street lighting.

C. <u>Issues Not Addressed in Settlement Agreement</u>. Mr. Rogers noted Section I.C of the Settlement Agreement sets forth the Setting Parties' agreement that any matters not addressed in the Settlement Agreement will be adopted as proposed by AES Indiana in its direct and rebuttal testimony.

D. <u>Time</u>. Mr. Rogers testified that Section II of the Settlement Agreement states that time is of the essence to the Settling Parties' Agreement.

E. <u>Nature</u>. Mr. Eckert stated the Settlement Agreement was the product of intense negotiations, with each party compromising upon challenging issues to reach an overall settlement that balances ratepayers' interests. The Settlement Agreement provides that neither the making of the Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding. Mr. Rogers testified the Settlement Agreement is a compromise and will be null and void unless approved in its entirety without modification or further condition that is unacceptable to any Settling Party. Mr. Rogers further testified the Settlement Agreement states the Settling Parties' agreement that the evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement, includes provisions concerning the substantial evidence in the record supporting the approval of the Settlement Agreement, recognizes the confidentiality of settlement communications, and reflects other terms typically found in settlement agreements before this Commission. Mr. Eckert further testified the Settlement Agreement is a fair resolution of the issues presented in this proceeding, is supported by the evidence, is in the public interest, and should be approved.

F. <u>Five Pillars</u>. Mr. Eckert detailed the ways in which the OUCC views the Settlement Agreement as satisfying each of the "Five Pillars" of ratemaking set forth in Ind. Code § 8-1-2-0.5.

Mr. Eckert stated that the Settlement Agreement reduces AES Indiana's requested revenue increase in several ways, thereby further protecting affordability. For example, the Settlement Agreement removes: (1) $24.933 million in depreciation expense using the ALG methodology; (2) $32.099 million in fuel costs; (3) $14.880 million by reducing AES Indiana's requested ROE from 10.6% to 9.9%; (4) $3.8 million in payroll expense; (5) $2.1 million in Other Operating Expense; and (6) other costs identified in his testimony and the Settlement Agreement.

He stated that the agreed-upon $25 million vegetation management expense and the continuation of the Major Storm Damage and Restoration Reserve support the reliability, resiliency, and stability pillars. He said the continuation of the storm reserve addresses the unpredictable nature of major storm timing, frequency, and damage.

Mr. Eckert also stated the settlement terms support environmental sustainability. Specifically, he said the rate increase reflected in the Settlement Agreement supports AES Indiana's provision of service. He noted Petitioner has an ongoing need for investment as part of its plan to transition from a coal-dominated generation fleet to a fleet consisting predominantly of renewables, storage, and natural gas. He stated by year-end 2025, AES Indiana plans to shut down its last coal plant and have placed in service new utility infrastructure and new renewable generating assets.

8. **Commission Discussion and Findings.** Settlement agreements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (*quoting Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406 (citation omitted).

In addition, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (*citing Citizens Action Coal. of Ind. v. Pub. Serv. Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreement, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that it serves the public interest. Here, the Settling Parties have presented substantial evidence from which we can assess the reasonableness of the terms of the Settlement Agreement.

We note that Indiana law strongly favors settlement as a means of resolving contested proceedings. *Mendenhall v. Skinner & Broadbent*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes.").

In the current Cause, the Commission has before it substantial evidence with which to judge the reasonableness of the terms of the Settlement Agreement. We recognize that all the parties in this proceeding joined the Settlement Agreement. These parties represent varied and competing customer groups and interests, encompassing all AES Indiana rate classes.

AES Indiana, the OUCC, and the intervening parties presented evidence supporting their initial respective positions. The evidence supports the existence of a test year revenue deficiency. Thus, while the amount of the necessary increase was in dispute, substantial evidence supports the conclusion that AES Indiana's present rates are unjust and unreasonable. Accordingly, we find it is reasonable and necessary for new rates and charges to be established.

The uncontested Settlement Agreement resolves all pending issues. Petitioner's case-in-chief supported a revenue deficiency of $134.2 million, which would reflect an overall revenue increase of 8.92%. Updates and concessions in AES Indiana's rebuttal testimony reduced the deficiency to $122.9 million, which reduced the identified overall rate revenue increase to 8.36%. As explained by Mr. Eckert, the Settling Parties agreed to an annualized combined basic rate and rider revenue requirement increase of $72.9 million, which was further reduced by approximately $1.9 million due to the capital cost update for the ACE Project. The Settlement Agreement also reflects approximately $100,000 in beneficial customer programs, the costs of which are not reflected in the agreed revenue deficiency.

As explained by OUCC witness Eckert, consumer benefits from the Settlement Agreement include: (1) a reduction of $24.933 million in depreciation expense using the ALG methodology; (2) a reduction of $32.099 million in fuel costs; (3) a savings of $14.880 million by reducing AES Indiana's requested ROE from 10.6% to 9.9%; (4) a reduction of $3.8 million in payroll expense; (5) a reduction of $2.457 million for regulatory asset amortizations; (6) a $2.905 million consumable expense reduction; (7) a reduction to the revenue requirement of $2.097 for Prepaid Pension Asset capital structure effects; (8) a reduction of $2.1 million in Other Operating Expense; (9) investment in environmental sustainability; (10) a reduction in AES Indiana's overall requested residential rate increase from 13.2% to 7.2%; (11) modifications to AES Indiana's proposed Economic Development Rider; and (12) investment in various community programs, including modifications to AES Indiana's proposed late payment charges and proposed disconnect and reconnect processes.

A. Agreed Revenue Deficiency Adjustments. As shown by the above summary of evidence, the Settlement Agreement enumerates the Settling Parties' agreed resolution of disputes regarding various operating expenses reasonably incurred to provide retail service, including wages and benefits, amortizations and rate case expense, NOx emission allowance expenses, vegetation management costs, certain outage maintenance costs, certain non-outage O&M costs, Major Project costs, and fuel costs. The overall terms of the Settlement Agreement and the supporting settlement testimony show the agreement on these ongoing costs is reasonable.

B. Depreciation. AES Indiana agreed for purposes of settlement, without waiving its right to propose alternative methodologies in the future, to use the OUCC and Industrial Group's proposed ALG procedure for depreciation rates. This Settlement Agreement provision results in a reduction to AES Indiana's identified depreciation expense of $24.8 million.

Even though the current methodology in place for AES Indiana is the ELG method, we believe the use of the ALG method is appropriate at this time given the utility's current investment cycle to determine the proper depreciation expense in this proceeding and because it contributes to bill affordability. The substantial expense decrease resulting from the change in depreciation method is a large factor in mitigating the potential bill impact from the proposed Settlement Agreement.

Based on the evidence presented, we find the Settling Parties' resolution of this issue, in conjunction with all other Settlement Agreement terms, is reasonable.

C. Cost of Capital Components.

i. ROE. The Settling Parties agreed that AES Indiana's ROE will be 9.9%, which is a reduction to AES Indiana's 10.6% ROE set forth in its case-in-chief. This negotiated result is within the range of the evidence and is consistent with the settlement testimony of Mr. Rogers. The record shows the capital structure used in AES Indiana's direct testimony to compute the overall rate of return for AES Indiana includes 44.69% common equity, which is equivalent to an equity ratio of approximately 47.44% after excluding cost-free items and tax credit balances. In his settlement testimony, Mr. Eckert noted that, from the OUCC's perspective, for settlement purposes, a 9.9% ROE more accurately reflects AES Indiana's risk profile than AES Indiana's proposed 10.60% ROE. He explained the lower ROE reduces the return on capital investment that consumers must pay through capital riders between rate cases and thus establishes a more balanced plan that is in the interest of ratepayers while still preserving the financial integrity of AES Indiana. Mr. Rogers' settlement testimony noted the equity rate percentage used in AES Indiana's direct testimony is lower than the 51.5% average common equity ratio for the firms in the Electric Group used in Petitioner witness McKenzie's analysis. The 9.9% ROE reduces AES Indiana's rate of return by $14.88 million, as compared to the utility's original ROE proposal, benefiting ratepayers.

We note that while the overall ROE agreed upon in this settlement is nine basis points lower than what was authorized in the previous rate case Order, the agreed-upon overall cost of capital in the Settlement Agreement is 26 basis points higher than what was authorized in the previous rate case Order. This is a function of an increased equity ratio. We further note the agreed-upon ROE in the present Cause is part of a negotiated package of terms that includes various reductions to AES Indiana's requested revenue requirement. Based on the evidence presented, we find the 9.9% ROE, when placed in context of the overall Settlement Agreement, is reasonable.

ii. **<u>Prepaid Pension Asset</u>.** The Settlement Agreement includes in AES Indiana's capital structure a Prepaid Pension Asset of $131.1 million, which reflects a reduction from AES Indiana's initial asset value of $166.2 million. Given the evidence presented and the Settlement Agreement as a whole, we approve this term.

D. **<u>ACE Project</u>.** The ACE Project is designed to replace a system that is more than 25 years old and which has reached its end of life. The Settlement Agreement includes total capital costs for developing and implementing the ACE Project, a Major Project, of $83.9 million, which is a reduction from the $94.2 million identified in AES Indiana's direct testimony. The record establishes that the ACE Project is in service, but no evidence was presented regarding the project efficiency of the system transition. Therefore, AES Indiana shall file monthly compliance reports under this Cause informing the Commission on the implementation of the ACE Project. Petitioner shall report any issues with the ACE Project, how the issues are being addressed, the number of customers affected, and any other information the Commission might request concerning the ACE Project. Petitioner shall submit its first such report within 30 days of the date of this Order and continue this reporting until directed otherwise by the Presiding Officers in a Docket Entry. Our consideration of the ACE Project, as with each term of the Settlement Agreement, is limited by the evidence presented at the December 19, 2023 evidentiary hearing. Based on this evidence, the compliance filing requirement noted above, and the Settlement Agreement as a whole, we approve the ACE Project settlement terms.

E. **<u>Vegetation Management</u>.** The Settlement Agreement embeds $25 million in basic rates for vegetation management and continues the mechanism established in Cause No. 45029 to address any cumulative shortfall in annual expenditures for vegetation management costs on AES Indiana's distribution facilities relative to the amount embedded in basic rates. Any such shortfall will be deferred. That deferral mechanism serves as a cap and no amounts spent above the amount embedded in base rates on a cumulative basis will be deferred. In AES Indiana's next base rate case, any balance in the established and continued regulatory liability will be amortized into the cost of service as a credit to the retail revenue requirement. We find the negotiated compromise reasonably addresses the OUCC and Intervenor concerns while also recognizing the need for the revenue requirement to reflect a reasonable level of vegetation management expense. We further find the agreement regarding vegetation management expense and the continuation of the Major Storm Damage and Restoration Reserve addresses and allows AES Indiana to maintain and help ensure the reliability, resiliency, and stability of its electric service.

F. Major Storms.

i. Major Storm Damage and Restoration Reserve and Major Storm Regulatory Liability. Section I.A.6.1 of the Settlement Agreement sets forth the Settling Parties' agreement to continue the Major Storm Damage and Restoration Reserve and to reflect a $6.1 million credit balance in rates as proposed by AES Indiana. We agree with the OUCC that this term will help address the unpredictable problem for ratemaking that occurs because the timing, frequency, and amount of potential damage from major storms is unpredictable. As such, we find the Settling Parties' compromise position to be reasonable.

ii. Storm Damage Recovery Procedure and Response. As noted above, the OUCC and CAC's Joint Petition remains pending in Cause No. 45917. The OUCC raised concerns in the current Cause as to whether AES Indiana (1) requested assistance from all of the available storm restoration services, (2) properly notified its customers on a timely basis through appropriate communication methods, and (3) provided accurate information to the Commission of the situation.

Mr. Holtsclaw's testimony established that AES Indiana deployed 104 line crews for the Level 3 June 29 storm. These crews consisted of 84 line crews which were ready to work at the start of the Level 3 June 29 storm and 20 additional contract line crews who arrived on June 30. These 104 total line crews exceed the 68 average number of line crews that AES Indiana deployed for Level 3 storm events since 2004. The evidence further established that AES Indiana deployed more line crews due to the June 29 storm than it had in the previous eight years for a storm of this magnitude. The uncontested evidence established that AES Indiana's response to the June 29 storm was equal to or better than the response provided by other utilities, as evidenced by a comparison of storm response with the information other utilities provided at a September 28, 2023 technical conference regarding their respective response The evidence also established that the priorities used to guide each utility's restoration efforts and overall effort were the same.

Mr. Holtsclaw also explained why the utility did not seek mutual assistance to help the utility recover from the storm. During the morning of Friday, June 30, the utility anticipated fully recovering from the storm by late Sunday (July 1) or early Monday (July 2). Given that line crews responding to a request for mutual assistance typically do not arrive until at least 24 hours after such a request is submitted, the utility's Incident Command team did not think additional mutual assistance crews could arrive in time to be of material assistance. This position is supported by the fact that if AES Indiana had requested and received such assistance, this may have hampered repair work elsewhere.

Mr. Holtsclaw also presented evidence to respond to OUCC witness Eckert's concerns about the utility's outage communications to its customers and the Commission. The evidence indicates that the utility began providing information through social media the afternoon of June 29 and that AES Indiana continued this effort by providing information through the weekend. The evidence also showed that any reporting issues were due to (1) issues with its Outage Management System, which the utility is replacing in 2024, (2) AES Indiana's July 4 outage report only included outages due to the June 29 storm, while the data the utility provided at the technical conference also included outages related to storms on June 30 and July 2, (3) technical limitations of its AMI, and (4) the utility learning more information about outages and providing updated information to the Commission.

Through Settlement Agreement Section I.A.6.2, the Settling Parties agreed to lower the threshold for AES Indiana to begin its 170 IAC 4-1-23(b)(1) outage reporting to 2,500 customers. This section also provides that AES Indiana will continue reporting until service is restored to all such customers. AES Indiana also agreed to meet with the OUCC and other interested Settling Parties to collaborate on any additional modifications to AES Indiana's storm reporting requirements and/or related procedures and will a submit a report under this Cause of any resulting recommendations to the Commission within 90 days of this Order. Based on the evidence provided, we find the Settlement Agreement terms regarding AES Indiana's storm response to be responsive to most of the concerns expressed by the OUCC and reasonable.

Mr. Holtsclaw also testified on rebuttal that the investigation in Cause No. 45917 is not warranted nor needed. Section I.C of the Settlement Agreement provides that the Settling Parties agree that any matters not addressed by the Settlement Agreement will be adopted as proposed by AES Indiana in its direct and rebuttal case. The Settling Parties do not reference Cause No. 45917 in the Settlement Agreement. The Settling Parties' incorporation of AES Indiana's conclusion into the Settlement Agreement is supportive of a determination that the issues raised in Cause No. 45917 have been resolved.

G. Revenue Allocation and Rate Design. Settlement Agreement Section I.B.7 provides that Attachment C to the agreement sets forth the Settling Parties' agreed revenue allocation. The Settling Parties agreed on an allocation that is without reference to any specific cost allocation methodology. Mr. Eckert testified that the OUCC considers the agreed settlement allocation a fair compromise in the context of the overall settlement. The parties agreed the settlement revenue allocation reflects "customer class revenue allocation factors" based on firm load with interruptible load removed as required by Indiana Code § 8-1-39-9(a)(1).

We note that the Industrial Group, Rolls-Royce, Walmart, and Kroger all represent or include customers with multiple C&I accounts across different rates and all participated in settlement discussions along with the OUCC, the statutory representative of all ratepayers, ultimately agreeing to the revenue allocation set forth in the Settlement Agreement in the context of the overall settlement. However, we also note that Small C&I customers are the only group that receives a higher revenue requirement in the Settlement than in the original proposal, as set forth as follows:

	W/O Settlement	W/ Settlement	Difference	%
Residential	$739,202,469	$705,274,511	$(33,927,958)	(4.6)%
Small C&I	$243,061,935	$244,868,766	$1,806,831	0.7%
Large C&I	$642,480,998	$622,455,180	$(20,025,818)	(3.1)%
Lighting	$19,729,075	$19,034,064	$(695,011)	(3.5)%
Total	$1,644,474,477	$1,591,632,521	$(52,841,956)	(3.2)%

The Presiding Commissioner at the evidentiary hearing questioned OUCC witness Eckert why it was equitable for Small C&I customers to solely be subjected to an increase under the agreement. Mr. Eckert explained the OUCC believes the overall revenue allocation was reached as part of a give-and-take of settlement negotiations and, when viewed in context of the Settlement Agreement as a whole, is reasonable. The Commission appreciates the challenge the OUCC and others have in balancing the interests of varied customer classes, but we must note a measure of concern that the balance is not often as favorable to the Small C&I classes as it is for other classes. We encourage the OUCC to consider and to the extent required in future settlements to ensure its balancing effort maintains a more equitable treatment among all classes. Notwithstanding this concern, and with consideration of the complexities inherent in settlement negotiations noted by Mr. Eckert and reasonable deference to the customer's statutory representative, the revenue allocation is not unreasonable.

As a result of the Settlement Agreement, AES Indiana's residential customer charge will be set at $12.50 for usage at or below 325 kWh; the charge will remain $17.00 for all other residential service usage. Both are reductions from AES Indiana's proposed charges and maintain the amount approved in Cause No. 45029. AES Indiana's declining block rate structure will be modified through a reduction of the second block differential by 25% with no change to the differential to the third block applicable to RH and RC customers. The Settlement Agreement partially preserves a rate structure that does not shift costs. It also creates incentives to invest in energy efficiency. The gradual movement in the fixed charge for lower usage, the maintenance of the current fixed charge for most customers, and the agreed change to AES Indiana's declining block energy charges are within the range of the evidence and reflect a reasonable resolution of these disputed issues. The Commission finds the negotiated compromise regarding the rate design, as a part of the overall Settlement Agreement, is reasonable and should be approved.

H. <u>FAC</u>. Settlement Agreement Section I.A.13.3 establishes a base cost of fuel of $0.039027 per kWh and reflects a fuel cost reduction of approximately $31.9 million compared to AES Indiana's evidence in its direct testimony. The Settlement Agreement continues the procedures currently in place for AES Indiana's fuel cost filings, including the procedural process that allows the OUCC and Intervenors to file their testimony and report not more than 35 days after AES Indiana's filing of its application. We find these agreements to be reasonable in light of the presented evidence.

I. <u>Disconnect/Reconnect Procedures</u>. Through Section I.A.12 of the Settlement Agreement, the Settling Parties agreed, with certain exceptions and requirements, to AES Indiana's request for a waiver of the 170 IAC 4-1-16(f) requirements that mandate an in-person visit by a company representative prior to disconnecting a customer's electric service. Under the settlement, AES Indiana will begin to remotely disconnect and reconnect customers using its AMI. AES Indiana will utilize phone calls, text, or email messages to communicate final disconnect notices to residential customers instead of conducting in person on-premises visits. As noted above, the OUCC raised concerns whether customers would receive sufficient notice regarding an impending disconnection of their service and the CAC discussed issues that such a proposal may have upon medically vulnerable customers.

The Settling Parties addressed the notification issue through the Settlement Agreement by setting forth an agreed-upon method for AES Indiana to notify its customers about the remote disconnect/reconnect program and about the importance of maintaining current contact information with the utility. The agreement even designates particular language, which includes recommendations proposed by OUCC witness Paronish, AES Indiana is to use for such communications.

The Settlement Agreement also lengthens the medical disconnection protection time for LIHEAP Qualified Participants who have a Medical Hold or a Medical Alert. For LIHEAP Medical Hold customers, the protection extends from 20 days to 30 days. Before any disconnection of LIHEAP Medical Hold customers, AES Indiana will place a collection call to such customer that prompts the customer to contact AES Indiana to establish an installment plan. For LIHEAP Medical Alert customers, the protection extends from 20 days to 40 days. AES Indiana will send such Medical Alert customer additional correspondence requesting the establishment of an installment plan.

The agreement also provides a mechanism to help improve Petitioner's customer education/outreach and Petitioner's procedures regarding the Medical Alert and Medical Hold Programs. Specifically, the agreement provides that within 90 days of Commission approval of the Settlement Agreement, AES Indiana will offer to meet with the CAC and OUCC regarding these topics.

The Settlement Agreement sets the fee for remote disconnection at zero dollars and the fee for remote reconnection at three dollars. The Settlement Agreement also states that AES Indiana will waive, once in a rolling 12-month period, the manual disconnection and manual or remote reconnection fees of a LIHEAP Qualified Participant. The Settlement Agreement further prohibits AES Indiana from disconnecting electrical service for residential customers on particular days and holidays, which is consistent with 170 IAC 4-1-16(d).

The proposed remote disconnect/reconnect process allows for efficiencies in the utility's disconnection and reconnection process, and reduces the operating costs related to the disconnection and reconnection process. In light of the detailed agreement regarding the remote disconnection and reconnection program and the Settlement Agreement as a whole, we approve the waiver of 170 IAC 4-1-16(f) requirements mandating an in-person visit by a company representative prior to disconnecting a customer's electric service, subject to AES Indiana's compliance with Settlement Agreement Section I.A.12.

J. <u>Other Terms</u>.

i. <u>Excess Distributed Generation, Multi-Family, and Low Load Factors</u>. Settlement Agreement Sections I.B.5, I.B.6, and I.B.8 require, among other things, AES Indiana to collect, analyze, and report certain data regarding its Excess Distributed Generation tariff and Small Power Production tariff, single- and multi-family cost differentials, and low load factors. These provisions are responsive to issues raised by the OUCC and the intervening parties. At the hearing, Mr. Rogers testified it would be reasonable to include information related to these three settlement provisions as part of AES Indiana's annual performance metrics reporting in Cause Nos. 44576 and 44602. In light of the evidence presented and the Settlement Agreement as a whole, we find Settlement Agreement Sections I.B.5., I.B.6., I.B.8., and Mr. Roger's proposed reporting to be reasonable. Petitioner shall provide the information required by Settlement Agreement Sections I.B.5., I.B.6., I.B.8. as part of AES Indiana's annual performance metrics reporting in Cause Nos. 44576 and 44602, beginning with its next report in each Cause.

ii. <u>City of Indianapolis</u>. Settlement Agreement Section I.B.10 sets forth the Settlement Agreement terms relating to the City's streetlighting rates, changing lights to use LED lights, and agreed-upon future discussions. Based on the evidence presented and the overall Settlement Agreement, we find these terms reasonable.

K. <u>Field Hearings and Customer Comments</u>. Approximately 50 individuals testified at the field hearings held in this Cause and the OUCC provided over 1,500 written customer comments, which were admitted as Public Exhibits 15 and 16. Mr. Eckert noted that the comments admitted as Public Exhibit 16 were previously filed in Cause No. 45917. This testimony and the written comments included concerns related to all five pillars set forth in Ind. Code § 8-1-2-0.6, with an emphasis on affordability, customer service, AES Indiana's system resilience and reliability, and the utility's proposed ROE.

L. <u>Indiana Code §§ 8-1-2-0.5 and -0.6</u>. Through Ind. Code § 8-1-2-0.5, the Indiana General Assembly established the state's policy recognizing utility service affordability for present and future generations. This legislative policy states affordability should be protected when utilities invest in infrastructure necessary for system operation and maintenance.

Through Ind. Code § 8-1-2-0.6, the Indiana General Assembly declared it is the continuing policy of the state that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of five pillars of electric utility service: reliability, affordability, resiliency, stability, and environmental sustainability.

We considered the affordability underlying the Settlement Agreement terms by considering the financial implications of the agreement as a whole, which included analyzing the largest drivers that impact affordability in rate cases; namely, return on equity, the depreciation methodology employed in the plan, the total revenue requirement, and the allocation of the revenue requirement.

We also considered reliability, resiliency, and stability issues, primarily through our review of the evidence regarding vegetation management, which address the single leading cause of outages at AES Indiana; the Major Storm Damage and Restoration Reserve, which addresses AES Indiana's ability to recover from storms; and AES Indiana's service interruption reporting requirements.

We additionally considered the environmental sustainability pillar, which considers the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation. On this point, Mr. Eckert stated AES Indiana needs to make continued investment as part of its generation mix transition. He noted that Petitioner plans to shut down its last coal plant by the end of 2025 and to place in service new utility infrastructure and new renewable generating assets.

The Commission has considered the five pillars enumerated in Ind. Code § 8-1-2-0.6 in reaching our decision in this proceeding. The Commission finds AES Indiana's proposals are consistent with the legislative directives.

9. **<u>Conclusion</u>.** The testimony supporting the Settlement Agreement explains why the Settlement Agreement, when considered as whole, is reasonable and in the public interest. As noted above, all customer classes (Residential, Small C&I, Large C&I, and Lighting) were represented by the Settling Parties throughout the settlement discussions. All customers benefit from a reduced ROE, which will be used in future capital cost recovery mechanisms. All customer classes also benefit from the Settlement Agreement in that the Settlement Agreement laid out commitments to analyze and research topics such as low load factor rates and LED lighting topics. Although the Settlement Agreement rate increase impacts customer classes differently, the overall Settlement Agreement package resulted in reasonable impacts that are a product of arm's-length negotiations. Further, the underlying cost allocation was aimed at balancing increases among classes. We are also persuaded to approve the Settlement Agreement because all parties of record, representing diverse interests, are signatories to the Settlement Agreement and they each recommend approval of the agreement.

Based upon our review of the record as a whole and consideration of the Settlement Agreement terms in totality and the admitted testimony and exhibits, the Commission finds that the Settlement Agreement represents a just and reasonable resolution of the issues.

Based upon the foregoing conclusion with respect to the Settlement Agreement, the Commission finds that the net original cost rate base for purposes of this Cause is $3,444,878 and is calculated as follows:

Net Original Cost Rate Base (thousands of dollars)	
Net Plant In Service	$ 3,024,046
Materials and Supplies Inventory	$ 111,035
Fuel Stock Inventory	$ 29,052
Regulatory Assets	$ 280,745
Total Original Cost Rate Base	**$ 3,444,878**

Joint Exhibit 1, Attachment CAR-2S, Schedule RB1-S-R. We find this original cost is the fair value under Indiana Code § 8-1-2-6 for purposes of this Cause.

Based on these findings and after giving effect to the Settlement Agreement terms regarding cost of capital, we find that Petitioner's capital structure and weighted cost of capital is as follows:

Description	Total AES Indiana Capitalization (thousands of dollars)	Percent Of Total	Cost Rate	Weighted Cost Rate
Long-Term Debt	$ 2,153,036	49.15%	4.90%	2.41%
Preferred Stock	$ -	0.00%	0.00%	0.00%
Common Equity	$ 1,943,109	44.36%	9.90%	4.39%
Customer Deposits	$ 35,097	0.80%	6.00%	0.05%
Prepaid Pension Asset (net of OPEB liability)	$ (133,100)	(3.04)%	0.00%	0.00%
Deferred Income Taxes	$ 382,560	8.73%	0.00%	0.00%
Post 1970 ITC	$ 24	0.00%	7.28%	0.00%
Totals	$ 4,380,726	100.00%		6.85%

Joint Exhibit 1, Attachment CAR-2S, Schedule CC2-S-R.

Based on the evidence presented, we find that AES Indiana should be authorized to increase its basic rates and charges to produce additional operating revenue of approximately $71,037,000 million. This revenue is reasonably estimated to afford AES Indiana the opportunity to earn a net operating income of $235,972,000, as shown on Joint Exhibit 1, Attachment CAR-2S, Schedule REVREQ1-S-R.

The Commission finds the Settlement Agreement is reasonable, supported by substantial evidence, and in the public interest. Accordingly, the Settlement Agreement is approved in its entirety.

10. Effect of Settlement Agreement. The Settling Parties agree that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC March 19, 1997).

11. Confidentiality. On June 28, 2023, Petitioner filed its motions for Protection and Nondisclosure of Confidential and Proprietary Information with supporting affidavits asserting that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-

14-3-4 and 8-1-2-29. Docket Entries were issued on July 21, 2023 and November 2, 2023, through which the Presiding Officers determined the information should be held confidential on a preliminary basis, after which the information was submitted under seal.

On October 12, 2023, the Industrial Group filed its Motion for Confidential Treatment of Portions of the Direct Verified Testimony of James R. Dauphinais. The Industrial Group explained that portions of Mr. Dauphinais' testimony consisted of materials which were provided by Petitioner as confidential responses to data requests and relate to individual customer usage. The Industrial Group included an affidavit in support of this request. The Industrial Group stated that the information it sought to protect was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. A Docket Entry was issued on November 2, 2023, through which the Presiding Officers determined the information should be held confidential on a preliminary basis, after which the information was submitted under seal.

After review of the information and consideration of the affidavits, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement, a copy of which is attached to this Order, is approved.

2. AES Indiana's proposed tariff, as modified by the Settlement Agreement, is approved.

3. Petitioner is authorized to adjust and increase its rates and charges for electric utility service to produce an increase in total annual operating revenues of approximately $71,037,000 in accordance with the findings above, which rates and charges shall be designed to produce total annual operating revenues of $1,705,842,000, which are expected to produce an annual net operating income of $235,972,000.

4. Petitioner shall file new schedules of rates and charges, along with its revised tariff under this Cause, consistent with the Settlement Agreement and the rates and charges approved above. Petitioner's new schedules of rates and charges shall be effective upon approval by the Commission's Energy Division. Consistent with Settlement Agreement Section I.A.16.1, new basic rates approved by the Commission will be implemented for service rendered on or after the date the Commission approves Petitioner's new tariff.

5. Petitioner is authorized to place into effect for accrual accounting purposes revised depreciation accrual rates as provided in the Settlement Agreement.

6. Petitioner is granted accounting authority for the implementation of the Settlement Agreement.

7. Petitioner is authorized to file updated factors for its rate adjustment mechanisms in accordance with this Order, and such changes shall be effective simultaneously with approval of Petitioner's new basic rates.

8. AES Indiana is granted a waiver of 170 IAC 4-1-16(f) requirements mandating an in-person visit by a company representative prior to disconnecting a customer's electric service, subject to AES Indiana's compliance with the Settlement Agreement and Finding No. 8.F.ii.above.

9. AES Indiana shall file monthly compliance reports under this Cause informing the Commission on the implementation of the ACE Project. Petitioner shall report any issues with the ACE Project, how the issues are being addressed, the number of customers affected, and any other information the Commission might request concerning the ACE Project. Petitioner shall submit its first such report within 30 days of the date of this Order and continue this reporting until directed otherwise by the Presiding Officers in a Docket Entry.

10. AES Indiana shall provide the information required by Settlement Agreement Sections I.B.5., I.B.6., I.B.8. as part of its annual performance metrics reporting in Cause Nos. 44576 and 44602, beginning with its next report in each Cause.

11. The information submitted under seal in this Cause pursuant to Petitioner's request for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29.

12. This Order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, AND VELETA CONCUR; ZIEGNER ABSENT:

APPROVED: APR 17 2024

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco Digitally signed by Dana Kosco
Date: 2024.04.17 11:07:54
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Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA ("AES INDIANA") FOR AUTHORITY TO INCREASE RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, AND FOR APPROVAL OF RELATED RELIEF, INCLUDING (1) REVISED DEPRECIATION RATES, (2) ACCOUNTING RELIEF, INCLUDING DEFERRALS AND AMORTIZATIONS, (3) INCLUSION OF CAPITAL INVESTMENTS, (4) RATE ADJUSTMENT MECHANISM PROPOSALS, INCLUDING NEW ECONOMIC DEVELOPMENT RIDER, (5) REMOTE DISCONNECT/RECONNECT PROCESS, AND (6) NEW SCHEDULES OF RATES, RULES AND REGULATIONS FOR SERVICE.	CAUSE NO. 45911

IURC
JOINT
EXHIBIT No. 1
12-19-23 AT
DATE REPORTER

STIPULATION AND SETTLEMENT AGREEMENT

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or "Company"), the Indiana Office of Utility Consumer Counselor ("OUCC"), AESI Industrial Group (Allison Transmission, Inc., Eli Lilly and Company, Indiana University, Indiana University Health, Marathon Petroleum Company LP, and Messer LLC ("IG" or "Industrial Group")), Citizens Action Coalition of Indiana, Inc. ("CAC"), The Kroger Co. ("Kroger"), Walmart Inc. ("Walmart"), Rolls-Royce Corporation ("Rolls-Royce"), and City of Indianapolis (collectively the "Settling Parties" and individually "Settling Party"), solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts, and counsel, stipulate and agree the terms and conditions set forth below represent a fair, just, and reasonable resolution of the matters set forth below, subject to their incorporation by the Indiana Utility Regulatory Commission ("Commission") into a final, non-appealable order ("Final Order")[1] without modification or further condition that may be unacceptable to any Settling Party. If the Commission does not approve this Stipulation and Settlement Agreement ("Settlement Agreement"), in its entirety, the entire Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Settling Parties.

[1] "Final Order" as used herein means an order issued by the Commission as to which no person has filed a Notice of Appeal within the thirty-day period after the date of the Commission order.

I. TERMS AND CONDITIONS.

A. REVENUE REQUIREMENT. The Settling Parties agree that AES Indiana's proposed revenue requirement should be decreased from $1,737.8 million to $1,644.5 million, a decrease of $93.244 million (which is a decrease of $61.145 million exclusive of change in base fuel costs) as stated below and reflected in the attached Settlement Agreement Attachment A (summary of revenue requirement impact of settlement terms):

1. ACE Project.

1.1. As recommended by IG witness Gorman and OUCC witness Lantrip, rate base will be adjusted downward by approximately $94,000 to remove the legacy system net remaining book costs from rate base. This adjustment is reflected in the revised Schedule RB3-S. The Company will also reduce pro forma operating costs by $140,547.

1.2. The ACE Project total capital costs to be reflected in rate base are $94.165 million.

1.3 Based on the testimony of OUCC witness Lantrip, IG witness Gorman, and AES Indiana witness Barbarisi, AES Indiana Financial Exhibit AESI-OPER Schedule OM 18 will be updated to reflect the reduced expense provided to the parties in discovery and will be revised to amortize estimated non-recurring costs, including surge staffing costs, over four years. A revised Schedule OM18-S is included herewith in Settlement Agreement Attachment B and includes the operating expense reduction set forth in Section 1.1 above.

2. Amortizations and Rate Case Expense.

2.1 The Regulatory Assets listed in Table 1 of OUCC witness Blakley's testimony and the rebuttal testimony of Company witness Aliff shall be amortized over a four-year amortization period. For consistency and as reflected in Company witness Aliff's rebuttal testimony, Table 1 will be modified to include the 20% HS7 Gas Conversion and this, too, will be amortized over a four-year period instead of the three-year period proposed in the Company's direct testimony.

2.2 As recommended by OUCC witness Lantrip, AES Indiana's proposed amortization periods for the regulatory assets identified in OUCC witness Lantrip's testimony and Company witness Aliff's direct testimony shall be approved as proposed by AES Indiana.

2.3 Based on the testimony of OUCC witness Baker, CAC witness Inskeep, and the rebuttal testimony of Company witnesses Aliff and Robinson, rate case expense will be reduced to $3.0 million and amortized over a period of four years.

3. Cost Of Capital.

3.1 Return On Equity ("ROE"). The agreed authorized return on equity shall be 9.90%.

3.2 Prepaid Pension Asset. A Prepaid Pension Asset of $131.1 million (reduced from $166.2 million) will be included in the capital structure.

3.3 Weighted Average Cost of Capital ("WACC"). After incorporating Sections 3.1 and 3.2 above, the agreed WACC to be applied to AES Indiana's original cost rate base is 6.85%.

3.4 Net Operating Income ("NOI"). AES Indiana's authorized NOI will be $236,673,000.

4. Depreciation Rates And Expense. Solely for purposes of compromise in this proceeding, AES Indiana will accept the OUCC and Industrial Group proposal to utilize the ALG procedure for depreciation rates, resulting in a reduction to depreciation expense of $24.8 million. The revised depreciation rates will be included with the Company's testimony in support of the Settlement Agreement for approval by the Commission. In its next rate case, while AES Indiana reserves its right to propose alternate depreciation methodologies, AES Indiana shall include in its testimony an update to its depreciation rates using the ALG procedure.

5. IURC Fee and Revenue Conversion Factor. Consistent with OUCC witness Blakley's testimony and the rebuttal testimony of Company witnesses Aliff and Robinson, the IURC Fee of $0.001468 will be used to determine the IURC Fee and the revenue conversion factor for pro forma present and proposed rates as reflected in Schedules OM28-S and REVREQ2-S (included herewith in Settlement Agreement Attachment B). The revenue conversion factor will be calculated to reflect this Settlement Agreement.

6. Major Storms.

6.1 The Major Storm Damage and Restoration Reserve shall be continued, and the $6.1 million credit balance shall be reflected in rates as proposed by AES Indiana.

6.2 AES Indiana agrees that the threshold for AES Indiana to begin reporting under 170 IAC 4-1-23(b)(1) shall be 2,500 customers and AES Indiana will continue reporting until its customer interruptions drop to 0 customers. AES Indiana agrees to meet with the OUCC and other interested Settling Parties to collaborate on any additional modifications to AES Indiana's storm reporting requirements and/or related procedures and will a submit a report under this Cause of any resulting recommendations to the Commission within 90 days of a Commission order approving this Settlement Agreement.

7. Non-Outage O&M. As recommended by OUCC witness Armstrong, the Settling Parties agree to Commission approval of AES Indiana Schedule OM-7.

8. Other Operating Expense Adjustments. Operating expenses will be reduced by $2.3 million to reflect a negotiated compromise of the disputed operating expense issues, including, but not limited to, CAC witness Inskeep's testimony regarding membership costs. This adjustment is reflected on Schedule OM22-S (included herewith in Settlement Agreement Attachment B).

9. Payroll Expense – Wages and Vacant Positions. Petitioner's Schedule OM15 will be lowered by $3.8 million inclusive of adjustment to Payroll Tax Expense on Schedule OTX3-S.

10. Petersburg Units 1 and 2 Regulatory Assets.

10.1 To resolve the issue raised by IG witness Gorman, the unrecovered net book value to be included in a regulatory asset balance for Unit 1 and Unit 2 will be reduced by a $4.152 million revenue requirement impact. This agreed adjustment is reflected on Schedule RB9-S (included herewith in Settlement Agreement Attachment B).

10.2 These regulatory assets will be amortized through the revenue requirement as proposed by AES Indiana.

11. Materials and Supplies. Based on testimony of OUCC witness Armstrong and the rebuttal testimony of Company witness Coklow, and solely for purposes of compromise, all test year NOx emission allowances will be removed from inventory, which will result in a pro forma decrease to rate base of $648,000 as reflected on AES Indiana Financial Exhibit AESI-RB, Schedule RB7-S (included herewith in Settlement Agreement Attachment B).

12. Remote Disconnect/Reconnect/New Billing Format. The Settling Parties agree to Commission approval of AES Indiana's proposals modified as follows:

12.1 In first quarter 2024, AES Indiana will issue communications to customers for three consecutive months on the importance of maintaining current contact information. AES Indiana shall state that one of the purposes for updating contact information is to alert customers of potential remote disconnects.

12.2 AES Indiana will issue notice to customers of the approved remote disconnect/reconnect program at least 30 days in advance of the implementation.

12.3 AES Indiana will use the language for communicating changes to customers as modified by OUCC witness Paronish in her testimony. Ms. Paronish's language will be modified to reference phone as well as text and email. Due to character limitations, SMS text communications will point customers to a webpage that uses Ms. Paronish's modified language.

12.4 As recognized by Ms. Paronish's testimony, the Company does not currently plan to implement changes to its residential bill format beyond those identified in the discovery referenced in this testimony. Should AES Indiana propose to further modify its residential customer bill within 18 months of an order approving this Settlement Agreement, the Company will provide a confidential copy of its proposed new bill format to the OUCC and CAC at least 45 days in advance of the date the Company plans to implement the changes so that the OUCC and CAC may review and have an opportunity to provide feedback. Any such feedback will be provided within 15 days after the Company provides a copy to the OUCC and CAC.

12.5 With respect to disconnections, AES Indiana agrees not to disconnect service for any residential customer on Fridays, Saturdays, Sundays, and the following Holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Friday after Thanksgiving Day, December 24, and Christmas Day.

12.6 The fee for remote disconnection shall be set at $0. The fee for remote reconnection shall be set at $3.

12.7 AES Indiana agrees that, once in a rolling 12-month period, the Company will waive the manual disconnection and manual or remote reconnection fees of a LIHEAP Qualified Participant as that term is defined in Section B.4 below.

12.8 If a residential customer is on the Medical Hold or Medical Alert Program, or a participant in the AMI Opt-Out Program, or does not have an AMI meter, or has not provided a phone number or email address, AES Indiana will make an on-premises visit on the day of disconnect.

12.9 Within 90 days of Commission approval of this Settlement Agreement, AES Indiana will offer to meet with the CAC and OUCC to collaborate regarding customer education/outreach and Company procedures regarding the Medical Alert and Medical Hold Programs, including but not limited to, the service status of these customers during system-wide outages, the potential use of automated texts and calls to Medical Alert and/or Medical Hold customers when there is an outage, and a Solar+Storage Initiative for Medical Alert/Medical Hold customers.

12.10 If the customer is a LIHEAP Qualified Participant, the current 20-day protection from disconnection for Medical Hold will increase to 30 days. A Medical Hold will not require proof of the reason for the hold. Before any disconnection, the Company will place a collection call to such customer that prompts the customer to contact the Company to establish an installment plan. Disconnection will be done in accordance with Section 12.8 above.

12.11 If the customer is a LIHEAP Qualified Participant and has established a Medical Alert with the Company, the current 20-day protection from disconnection will increase to 40 days. AES Indiana will send such Medical Alert customer additional correspondence requesting the establishment of an installment plan.

13. <u>Riders</u>.

13.1 <u>ECR</u>.

13.1.1 As recommended by OUCC witness Armstrong, AES Indiana's proposed tracking of consumables shall be approved subject to the modification that the amount of consumables cost embedded in the base rate revenue requirement shall be reduced by $2.9 million as shown on AES Indiana Schedule OM5-S (included herewith in Settlement Agreement Attachment B).

13.1.2 As recommended by OUCC witness Armstrong, AES Indiana's Schedule OM8 and the associated proposal to remove test year emission allowance costs and track 100% of these costs through the ECR will be approved.

13.2 EDR.

13.2.1 The Economic Development Rider will be approved as proposed by AES Indiana provided that prior to implementation AES Indiana will provide the OUCC and CAC with its internal policy manual outlining the criteria that will be used to determine the discount for qualifying customers consistent with the Evaluation Criteria in Standard Contract Rider No. 27 (EDR) included with the Company's filing as AES Indiana Attachment AJB-2. Any feedback regarding the criteria will be provided within 15 days after the Company provides a copy of the internal policy manual.

13.2.2 AES Indiana will report annually to the IURC, OUCC, and CAC the name of customers receiving service under the EDR, and the incentive amount provided subject to the protection of confidential, competitively sensitive information from disclosure.

13.3 FAC.

13.3.1 The Company's base cost of fuel will be updated as recommended by OUCC witness Eckert and presented in the rebuttal testimony of Company witnesses Robinson and Steiner, which update reflects a fuel cost reduction of approximately $31.9 million. The new base cost of fuel is $0.039027 per kWh as calculated in AES Indiana Schedule OM2-S (included herewith in Settlement Agreement Attachment B).

13.3.2 The Company's proposal to move the Lakefield PPA adjustment to the OSS Rider so that all OSS margins will be reflected in the OSS Rider will be approved.

13.3.3 As stated in the testimony of OUCC witness Eckert, the Settling Parties agree to continue the agreement between AES Indiana and the OUCC that allows the OUCC and intervenors to file their FAC related testimony and report not more than 35 days after AES Indiana files its application and testimony.

13.4 OSS/CAP/RTO.

13.4.1 As recommended by OUCC witness Lantrip, AES Indiana Schedule REV6 will be approved. The retail revenue requirement shall embed $28.6 million of OSS margins as a benchmark for the OSS Rider as proposed by AES Indiana.

13.4.2 AES Indiana Schedule REV9 will be approved. The Company's proposal to embed $19 million in the retail revenue requirement as the benchmark for the CAP Rider will also be approved.

13.4.3 The retail revenue requirement shall embed MISO Non-fuel costs and revenues of $35.8 million and $3.6 million respectively as benchmarks for the RTO Rider as proposed by AES Indiana.

13.5 Interruptible Tariff/Rider 19. AES Indiana's proposed Rider 19 (Interruptible Demand Response) shall be modified to expand customer class eligibility to include rates PH, SH, and SS and to allow aggregation of smaller commercial customers with demand less than the 100 kW minimum in this basic rate proceeding. AES Indiana will collaborate with the DSM Oversight Board on adding a minimum dollar per kilowatt value for the rate in Rider 19 and expanding terms and conditions of participation as part of the next DSM Plan. While rate RS will not be included in Rider 19 as part of this Settlement, the Company will continue to include a residential demand response aggregation program proposal for rate RS to participate in Rider 19 in the broader Request for Proposals the Company is working to issue in 2023 to facilitate development of its next DSM Plan. To the extent the DSM Oversight Board finds adding rate RS to Rider 19 is a viable option, in the Company's DSM Plan proceeding to be initiated in 2024, the Company will report on this collaboration, present recommendations, and Rider 19 will be updated as necessary as part of that proceeding.

14. AES Services Agreement. As recommended by OUCC witness Lantrip, the Settling Parties agree to Commission approval of AES Indiana's Adjustment OM-23, subject to the requirement that AES Indiana update the Commission and the Setting Parties on the status of the service agreement remaining in place beyond the beginning of January 2024. This notice will be provided by AES Indiana submitting a compliance filing in this docket.

15. Vegetation Management. $25 million will be embedded in base rates for vegetation management on AES Indiana's distribution facilities as reflected in Schedule OM12-S (included herewith in Settlement Agreement Attachment B). The Vegetation Management Reserve will continue as established in Cause No. 45029. Pursuant to this Reserve, any shortfalls in annual vegetation management expenditures relative to the agreed amount embedded in base rates will be deferred. This deferral mechanism serves as a cap, and no amounts spent above the amount embedded in base rates on a cumulative basis will be deferred. In the Company's subsequent base rate case, any balance in this regulatory liability will be amortized into the cost of service as a credit to the retail revenue requirement.

16. Other.

16.1 Solely as a matter of compromise, the Settling Parties agree that the new basic rates approved by the Commission will be implemented by the Company for service rendered on and after the date the Commission approves the Company's new tariff assuming such approval comes expeditiously and no more than 20 days after the Company files its compliance tariffs in this proceeding.

16.2 The interest synchronization calculation will be calculated to reflect this Settlement Agreement.

16.3 Any revenue requirement matters not addressed by this Settlement Agreement will be as proposed by AES Indiana in its direct and rebuttal case.

16.4 AES Indiana will provide $50,000 in 2024 to help fund the "Power of Change" program and $50,000 to the Indiana Community Action Association to enable income qualified weatherization of homes within AES Indiana's service area. AES Indiana's revenue deficiency in this Cause will not be adjusted to include the cost of this contribution.

B. COST OF SERVICE, RATE DESIGN AND OTHER ISSUES.

1. **Residential Customer Charge.** The Settling Parties agree to the following AES Indiana residential fixed, monthly customer charges:

kWh/mo.	Settlement
≤ 325	$12.50
> 325	$17.00

2. **Declining Block Rate.** With respect to AES Indiana's declining block rates, the Settling Parties agree to a reduction in the second block differential of 25%, with no change to the differential to the third block applicable to RH and RC customers. With the agreed residential customer charge and this modification to the block structure, the residential energy charges will be calculated to recover the remaining residential revenue requirement. This is calculated to result in the following residential energy charges:

kWh	Settlement
First 500 kWh per month	$0.125583
Over 500 kWh	$0.113985
With electric heating and/or water heating over 1000 kWh	$0.101571

3. **Residential Late Payment Charge.** AES Indiana agrees that, once in a rolling twelve-month period, the Company will waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of net amount of the next succeeding month's bill.

4. **LIHEAP Customer Deposit.** If an applicant for residential service or current customer is qualified by the Community Action Agency to participate in the Low Income Home Energy Assistance Program ("LIHEAP Qualified Participant"), the residential deposit amount will be limited to $50.00. LIHEAP qualification can be from the current or one-year prior heating season.

5. **EDG Reporting.** As part of the annual performance metrics reporting in Cause Nos. 44576 and 44602, AES Indiana agrees to include monthly data that separately provides data on EDG tariff and Small Power Production tariff customer participation, broken down by residential and non-residential customers, and including data on both new and total (a) capacity

(kW-ac) installed, (b) number of customers, and (c) size of battery storage system (both kW and kWh) if one is part of the customer's system and that detail is provided to the Company by the customer.

6. Multi-Family Rate. AES will collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. AES will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, AES will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested Settling Party the results of its analysis.

7. Revenue Allocation.

7.1 The Settling Parties agree that rates should be designed in order to allocate the revenue requirement to and among AES Indiana's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that Settlement Agreement Attachment C specifies the revenue allocation agreed to by all Settling Parties. This revenue allocation is determined strictly for settlement purposes and is without reference to any particular, specific cost allocation methodology. The demand allocators for AES Indiana's rate adjustment mechanisms are set forth in Settlement Agreement Attachment D.

7.2 The Settling Parties agree that Settlement Agreement Attachment E presents the "customer class revenue allocation factor[s] based on firm load," as that phrase is used in IC 8-1-39-9(a)(1) for recovery of transmission-related and distribution related costs. The Settling Parties agree that all revenues and allocation factors on Settlement Agreement Attachment E have had interruptible load removed. The Settling Parties also agree that Settlement Agreement Attachment E reflects the percentage of distribution and transmission costs allocable to each individual Rate Code.

8. Rate Design, Cost of Service and Other Issues. Prior to filing its next basic rate case, AES Indiana will discuss with Kroger, Walmart, Rolls-Royce and the Industrial Group, the creation of a low load factor rate. The Company agrees to prepare a low load factor analysis, including seeking input on eligibility criteria and other related issues in a timely manner sufficient to afford the named parties a reasonable opportunity to provide meaningful input prior to the filing of the case. The Settling Parties agree that AES Indiana is not obligated to propose a low load factor rate or take a position in support of or against any such rate structure in its next basic rate case. The Company will make the aforementioned analysis available to the other parties, but the Company is not required to include the analysis as part of its basic rate case filing though it will not oppose the use of the analysis, or modifications thereof by other parties. The Settling Parties further agree that all parties, including AES Indiana, will have the opportunity to take any position with respect to the aforementioned analysis as they deem appropriate in the next basic rate case and each reserves the right to present their own alternative analysis and proposals.

9. Other Customer Charges Pro Forma Adjustment. Other customer charges will include a $1.0 million pro forma adjustment to reflect a negotiated compromise to reduce the Residential revenues portion of total sales of electric energy. This adjustment is reflected on Schedule REV10-S, Line 10 (included herewith in Settlement Agreement Attachment B).

10. City of Indianapolis.

10.1 Rates. The agreed rates for Tariff MU-1 customers set forth in Settlement Agreement Attachment F shall be approved.

10.2 LED Change Out. AES Indiana shall analyze and develop a written report regarding the remaining Company owned HPS and MV lights, including ornamental lighting, and the cost and associated customer rate impact to convert such lights to LED lights of comparable illumination. The Company will solicit input from the City, other street lighting customers, and other interested Settling Parties on this analysis. The Company's report shall be submitted to the Commission as a compliance filing in this docket (subject to the protection of confidential information) within two years after issuance of a Commission Final Order approving this Settlement Agreement.

10.3 AES Indiana's Next Basic Rate Case. In its next basic rate case, AES Indiana will present an analysis of LED street lighting O&M versus other street lighting O&M and an analysis of whether LED street lighting should be treated as a separate class or subclass of street lighting. Within this analysis, the Company will differentiate the energy, customer accounts, O&M, and depreciation. While AES Indiana has agreed to conduct the aforementioned analysis, the Settling Parties agree that AES Indiana is not obligated to propose that LED street lighting be treated as a separate class or subclass or take a position in support of or against any particular rate structure in its next basic rate case. The Settling Parties further agree that Settling Parties, including AES Indiana, will have the opportunity to take any position with respect to the aforementioned analysis as they deem appropriate in the next basic rate case, and each Settling Party reserves the right to present its own alternative analysis and proposal.

10.4 Streetlight relocations for capital projects. AES Indiana agrees that when streetlights under the Tariff MU-1 City Street Lighting with CIAC rates agreed to in this Settlement Agreement ("City CIAC Rate(s)") are required to be relocated for a capital improvement project, regardless of the distance of the relocation, such street lights shall not be considered "new construction" provided the existing facilities are re-used in the new location. AES Indiana will make reasonable efforts to re-use the existing facilities and will advise the City if the facilities cannot be re-used and the reasons for its inability to do so. In this scenario, the City will be charged the applicable City CIAC Rate for ongoing energy service to the street light. This Section does not address the obligation to pay for the relocation of the facilities. Nothing in this Paragraph shall be interpreted to conflict with the City Revised Code Sections 645-701 through 645-706, or as amended, or 170 Ind. Admin. Code 4-1-28.

10.5 Other. AES Indiana and the City agree to engage in discussions within 60 days of the final evidentiary hearing on this Settlement Agreement (irrespective of a final order in this docket) regarding: response time in repair and replacement of lights that have been reported as out/broken by the City; advancement of the current list of planned light placement still available under the current contract; ornamental street lighting repair; relocation issues and costs within the City's rights of ways; vegetation management around street lighting; and the placement of temporary lighting on private construction projects when street lighting is removed for the project, and other issues as needed. These discussions shall occur no less often than quarterly, with those with the appropriate decision making authority from both AES Indiana and the City present. The City and AES Indiana agree that the first meeting shall specifically address planned and pending (but not yet installed) street lighting and AES Indiana's vegetation management policy around street light infrastructure for which the City is a customer. At this first meeting, AES Indiana and the City shall discuss a longer term plan for the installation of additional lights and/or conversion of existing street lights to LED.

C. **REMAINING ISSUES.** Any matters not addressed by this Settlement Agreement will be adopted as proposed by AES Indiana in its direct and rebuttal case.

II. PRESENTATION OF THE SETTLEMENT AGREEMENT TO THE COMMISSION.

A. The Settling Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement by the April 24, 2024 target order date.

B. The Settling Parties may file testimony specifically supporting the Settlement Agreement. The Settling Parties agree to provide each other with an opportunity to review drafts of testimony supporting the Settlement Agreement and to consider the input of the other Settling Parties. Such evidence, together with the evidence previously prefiled in this Cause, will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties submit this Settlement Agreement and related evidence conditionally, and if the Commission fails to approve this Settlement Agreement in its entirety without any change or condition(s) unacceptable to any Settling Party, the Settlement and supporting evidence shall be withdrawn, and the Commission will continue to hear Cause No. 45911 with the proceedings resuming at the point they were suspended by the filing of this Settlement Agreement.

C. A Commission Order approving this Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective, and binding on all Settling Parties upon incorporation and approval in a Final Order of the Commission.

III. EFFECT AND USE OF SETTLEMENT AGREEMENT.

A. It is understood that this Settlement Agreement is reflective of a negotiated settlement, and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except to the extent necessary to implement and enforce its terms. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

B. Neither the making of this Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this

Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

C. This Settlement Agreement shall not constitute and shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Settlement Agreement.

D. This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

E. The Settling Parties agree the evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. The Settling Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible after the filing of this Settlement Agreement and the final evidentiary hearing.

F. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

G. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their respective clients, and their successor and assigns, which will be bound thereby.

H. The Settling Parties shall not appeal or seek rehearing, reconsideration, or a stay of the Commission Order approving this Settlement Agreement in its entirety and without change or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement Agreement).

I. The provisions of this Settlement Agreement shall be enforceable by any Settling Party upon approval and incorporation into a Final Order first before the Commission and thereafter in any state court of competent jurisdiction as necessary.

J. This Settlement Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED and AGREED as of the 22nd day of November, 2023.

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CONSOLIDATED CITY OF INDIANAPOLIS AND MARION COUNTY

____

Matt Giffin
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Consolidated City of Indianapolis and Marion County

AES Indiana 2023 Basic Rate Case
Settlement Agreement Attachment A

Revenue Requirement Impact

(in 000s)

Item	Final Settlement RevReq Impact	Revenue Requirement	AES Indiana Exhibit AESI-OPER Schedule
Starting Point - AES Indiana Direct		$ 1,737,766	OPINC
Remove ACE Legacy RB - $94k	$ (7)	$ 1,737,759	RB3
ACE O&M Reduce by $3.041M	$ (3,058)	$ 1,734,701	OM18
Remove ACE Legacy O&M by $141k	$ (143)	$ 1,734,558	OM18
Amortize 3 yrs to 4 yrs - Reg Assets	$ (2,457)	$ 1,732,101	RB9
Reduction of Rate Case Expense to $3.0M	$ (665)	$ 1,731,436	OM21
Amortize 3 yrs to 4 yrs - RC Exp	$ (251)	$ 1,731,185	OM21
ROE in Cost of Capital 10.6% to 9.90%	$ (14,880)	$ 1,716,305	CC2
PPD Pension in Cost of Capital from $166.2 to $131.1	$ (2,097)	$ 1,714,208	CC2
Depreciation Expense - Change methodology to ALG	$ (24,933)	$ 1,689,275	DEPR
IURC Fee Update	$ 513	$ 1,689,788	OM28, REVREQ2
Reduction to O&M Expense	$ (2,279)	$ 1,687,509	OM22
O&M Payroll Decrease by $3.5M	$ (3,493)	$ 1,684,016	OM15
O&M Payroll Tax Decrease by $0.3M	$ (283)	$ 1,683,733	OTX3
Extend Amortization of Pete 1 and 2 - Reduce RB	$ (4,152)	$ 1,679,581	RB9
Remove NOx Inventory in RB by $648k	$ (55)	$ 1,679,526	RB7
Consumables - lower benchmark	$ (2,905)	$ 1,676,621	OM5
Base Cost of Fuel Reduction	$ (32,099)	$ 1,644,522	OM2
Total Decrease in Revenue Requirment	$ (93,244)		
Base Cost of Fuel	$ 32,099		
Total Decrease in Rev Req less Base Cost of Fuel	$ (61,145)		

AES Indiana Direct:	Total Op Revenue	Total Sales of Electric Energy
Revenue Deficiency	$ 134,242	$ 138,290
Revenues at Present Rates Pro Forma	$ 1,603,524	$ 1,578,113
Overall Increase	**8.37%**	**8.76%**
AES Indiana Rebuttal:		
Revenue Deficiency	$ 122,880	$ 126,928
Revenues at Present Rates Pro Forma	$ 1,571,599	$ 1,546,189
Overall Increase	**7.82%**	**8.21%**
AES Indiana Settlement:		
Revenue Deficiency	$ 72,923	$ 75,971
Revenues at Present Rates Pro Forma	$ 1,571,599	$ 1,546,189
Overall Increase	**4.64%**	**4.91%**

AES Indiana 2023 Basic Rate Case
Settlement Agreement Attachment B

AES Indiana
Weighted Average Cost of Capital
(Thousands of Dollars)

Line No.	Component of Capitalization	Balance at December 31, 2022 (Col. 1)	Percent of Total (Col. 2)	Return Rate (Col. 3)	Weighted Return Rate (Col. 4)	Line No.
1	Long-Term Debt	$ 2,153,036	49.15 %	4.90 %	2.41 %	1
2	Preferred Stock	—	— %	— %	— %	2
3	Common Equity	1,943,109	44.36 %	9.90 %	4.39 %	3
4	Customer Deposits	35,097	0.80 %	6.00 %	0.05 %	4
5	Prepaid Pension Asset (net of OPEB liability)	(133,100)	(3.04)%	— %	— %	5
6	Deferred Income Taxes	382,560	8.73 %	— %	— %	6
7	Post 1970 ITC	24	— %	7.28 %	— %	7
8	Totals	$ 4,380,726	100.00 %		6.85 %	8

(1) Please see AES Indiana Attachment HMR-2

(2) Provided by AES Indiana Witness McKenzie

(3) Computed as the weighted return on investor-supplied capital:

Long-Term Debt	$ 2,153,036	52.56 %	4.90 %	2.58 %
Preferred Stock	—	— %	— %	— %
Common Equity	1,943,109	47.44 %	9.90 %	4.70 %
	$ 4,096,145	100.00 %		7.28 %

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper CC2.

AES Indiana
Allowable Electric Operating Income Requirement
(Thousands of Dollars)

Line No.		(Col. 1)	Supporting AES Indiana Financial Exhibit Reference (Col. 2)	Line No.
1	Original cost rate base	$ 3,455,111	AESI-RB, Schedule RB1 Column 6, Line 9	1
2	Rate of return	6.85 %	AESI-CC, Schedule CC2	2
3	Allowable electric operating income	236,673	Line 1 multiplied by Line 2	3
4	Less: Electric operating income pro forma at present rates	$ 182,052	AESI-OPER, Schedule OPINC, Column 4, Line 13	4
5	Deficiency in electric operating income	54,621		5
6	Revenue conversion factor	0.747322	AESI-REVREQ, Schedule REVREQ2, Line 19	6
7	Deficiency in electric operating revenue	$ 73,090	Line 5 divided by Line 6	7
8	Additional operating revenue produced by proposed rates	$ 73,090	AESI-OPER, Schedule OPINC, Column 5, Line 1	8

AES Indiana
Gross Revenue Conversion Factor
At December 31, 2022

Line No.			(Col. 1)	Supporting AESI Financial Exhibit Reference (Col. 2)	Line No.
1	Revenue		1.000000		1
2	Less:	Uncollectibles	0.003814	AESI-OPER, Schedule OM27	2
3		Public utility fee	0.001468	AESI-OPER, Schedule OM28	3
4	State tax base		0.994718		4
5	Times: State tax rate		0.049000	AESI-OPER, Schedule TX3	5
6	Effective state tax rate		0.048741		6
7	Revenue		1.000000		7
8	Less:	Uncollectibles	0.003814	AESI-OPER, Schedule OM27	8
9		Public utility fee	0.001468	AESI-OPER, Schedule OM28	9
10		Effective state tax rate	0.048741	Line 6, above	10
11	Federal tax base		0.945977	Line 7, less Lines 8-10	11
12	Times: Federal tax rate		0.210000	AESI-OPER, Schedule TX2	12
13	Effective federal tax rate for taxable income		0.198655		13
14	Revenue		1.000000		14
15	Less:	Uncollectibles	0.003814	AESI-OPER, Schedule OM27	15
16		Public utility fee	0.001468	AESI-OPER, Schedule OM28	16
17		Effective state tax rate	0.048741	Line 6, above	17
18		Effective federal tax rate for income	0.198655	Line 13, above	18
19	Revenue conversion factor		0.747322		19

AES Indiana
Original Cost Electric Rate Base
Per Books at December 31, 2022 and Pro Forma
(Thousands of Dollars)

Line No.	Description	Plant in Service (Col. 1)	Accumulated Depreciation And Amortization (Col. 2)	Materials and Supplies Inventory (Col. 3)	Fuel Stock Inventory (Col. 4)	Regulatory Assets (Col. 5)	Totals (Col. 6)	Line No.
1	Per books (Schedules RB2, RB7, RB8, RB9)	$ 7,077,649	$ (4,057,940)	$ 115,958	$ 55,780	$ 404,947	$ 3,596,393	1
2	Add ACE Project (Schedule RB3)	94,071	—	—	—	—	94,071	2
3	Remove Eagle Valley Outage Capital Costs and Pete 2 and Pete 1 & 2 Shared Assets (Schedule RB4)	(512,743)	492,909	—	—	—	(19,834)	3
4	Remove non-jurisdictional MISO MTEP plant in service (Schedule RB5)	(20,788)	3,447	—	—	—	(17,341)	4
5	Remove net asset retirement cost (Schedule RB6)	(196,676)	154,349	—	—	—	(42,326)	5
6	Adjustment to materials & supplies inventory (Schedule RB7)	—	—	(4,923)	—	—	(4,923)	6
7	Adjustment to fuel stock inventory (Schedule RB8)	—	—	—	(26,728)	—	(26,728)	7
8	Adjustment to regulatory assets (Schedule RB9)	—	—	—	—	(124,202)	(124,202)	8
9	Pro forma original cost rate base	$ 6,441,514	$ (3,407,235)	$ 111,035	$ 29,052	$ 280,745	$ 3,455,111	9

AES Indiana
Pro Forma Adjustment to Include Addition of ACE Project
(Thousands of Dollars)

Line No.	Description	Total Projected Project Costs (Col. 1)	Total Per Books In Service at Dec 31, 2022 (Col. 2)	Pro Forma Adjustment (Col. 3)	Line No.
1	Miscellaneous Intangible Plant (Software System)	$ 89,167	$ —	$ 89,167	1
2	AFUDC	4,904	—	4,904	2
3	Net projected and per book totals	$ 94,071	$ —	$ 94,071	3
4	Net pro forma addition to plant in service (See Schedule RB1, Line 2, Column 1)			$ 94,071	4

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB3.

AES Indiana
Electric Materials and Supplies Inventory
Per Books at December 31, 2022 and Pro Forma
(Thousands of Dollars)

Line No.		T&D Non-Capital Spare 5 Mo. Average	Other Materials & Supplies 13 Mo. Average	Total Average	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	December 31, 2021	$ —	$ 60,653		1
2	January 31, 2022	—	60,990		2
3	February 28, 2022	—	61,421		3
4	March 31, 2022	—	61,590		4
5	April 30, 2022	—	61,697		5
6	May 31, 2022	—	61,035		6
7	June 30, 2022	—	60,159		7
8	July 31, 2022	—	60,794		8
9	August 31, 2022	43,555	61,239		9
10	September 30, 2022	49,360	61,598		10
11	October 31, 2022	50,616	61,719		11
12	November 30, 2022	51,610	61,904		12
13	December 31, 2022	53,335	62,623		13
14	Average	$ 49,695	$ 61,340	$ 111,035	14
15	Less: Per books at December 31, 2022			115,958	15
16	Pro forma adjustment (Line 14, less Line 15) (See Schedule RB1, Line 6, Column 3)			$ (4,923)	16

AES Indiana 2023 Basic Rate Case
Settlement Agreement Attachment B
Schedule RB7-S

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB7.

AES Indiana
Regulatory Assets Includable as Electric Rate Base
(Thousands of Dollars)

Line No.	Description	Regulatory Asset Balance at 12/31/2022	Projected Activity Through 5/31/2023	Less: Temporary Rates Credit	Pro Forma Adjusted Balances	Annual Amortization to Electric Cost of Service		Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)		
1	Unamortized Petersburg Unit No. 4 deferred costs and carrying charges: Unit 4 depreciation and post-in-service AFUDC deferred from the April 28, 1986 in-service date through the August 6, 1986 IURC order in Cause No. 37837	$ 2,478			$ 2,478	$ 676		1
2	Unamortized post in-service AFUDC from the August 6, 1986 IURC order in Cause No. 37837 through the August 24, 1995 IURC order in Cause No. 39938	1,388			1,388	379		2
3	Total Petersburg Unit No. 4 deferred costs	3,866			3,866	1,055	(1)	3
4	Unamortized post in-service AFUDC on projects approved in the November 14, 2002 IURC order in Cause No. 42170, the November 30, 2004 IURC order in Cause No. 42700, the April 2, 2008 IURC order in Cause No. 43403, the August 14, 2013 IURC order in Cause No. 44242, and the July 29, 2015 IURC order in Cause No. 44540	10,833			10,833	988	(2)	4
5	Unamortized deferred depreciation on projects approved in the April 2, 2008 IURC order in Cause No. 43403, the August 14, 2013 IURC order in Cause No. 44242, and the July 29, 2015 IURC order in Cause No. 44540	14,012			14,012	1,401	(3)	5
6	Depreciation of NAAQS-DBA deferred per the April 26, 2017 order in Cause No. 44794	36			36	4	(4)	6
7	Unamortized post in-service AFUDC for NAAQS-DBA per the April 26, 2017 order in Cause No. 44794	71			71	7	(5)	7
8	Depreciation of CCR Bottom Ash deferred per the April 26, 2017 order in Cause No. 44794	847			847	85	(6)	8
9	Unamortized post in-service AFUDC for CCR Bottom Ash per the April 26, 2017 order in Cause No. 44794	353			353	35	(7)	9

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
10	Depreciation of NAAQS-Other projects deferred per the April 26, 2017 order in Cause No. 44794	$ 471			$ 471	$ 47	(8)	10
11	Unamortized post in-service AFUDC for NAAQS-Other projects per the April 26, 2017 order in Cause No. 44794	359			359	36	(9)	11
12	Depreciation of Eagle Valley CCGT and Harding Street 5 & 6 Refueling deferred per the May 14, 2014 IURC order in Cause No. 44339	16,335			16,335	838	(10)	12
13	Unamortized post in-service AFUDC for the Eagle Valley CCGT and Harding Street 5 & 6 refueling per the May 14, 2014 IURC order in Cause No. 44339	33,110			33,110	1,643	(11)	13
14	Electric vehicle regulatory asset deferred per the March 18, 2015 IURC order in Cause No. 44478	625			625	106	(12)	14
15	Harding Street Unit 7 Preservation Costs deferred per the June 22, 2016 IURC order in Cause No. 42170 - ECR 26	1,482			1,482	423	(13)	15
16	20% HS7 Gas Conversion revenue requirement deferred per the July 29, 2015 IURC order in Cause No. 44540	(2,151)			(2,151)	(538)	(14)	16

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
17	20% NPDES revenue requirement deferred per the July 29, 2015 IURC order in Cause No. 44540	$ 14,439			$ 14,439	$ 3,610	(14)	17
18	20% NAAQS DBA revenue requirement deferred per the April 26, 2017 IURC order in Cause No. 44794	719			719	180	(15)	18
19	20% CCR Bottom Ash revenue requirement deferred per the April 26, 2017 IURC order in Cause No. 44794	1,593			1,593	398	(15)	19
20	20% NAAQS Other revenue requirement deferred per the April 26, 2017 IURC order in Cause No. 44794	2,198			2,198	549	(15)	20
21	Unamortized Petersburg Unit 1 capital costs at retirement date deferred per the November 17, 2021 IURC order in Cause No. 45502	40,876			40,876	5,000	(16)	21
22	Unamortized Petersburg 2 (& Pete 1&2 Shared) capital costs at retirement date deferred per the November 17, 2021 IURC order in Cause No. 45502	239,920	(124,202)		115,718	11,572	(16.1)	22
23	Depreciation of TDSIC deferred per the March 4, 2020 IURC order in Cause No. 45264, original filing	6,737			6,737	189	(17)	23
24	Unamortized post in-service AFUDC for TDSIC per the March 4, 2020 IURC order in Cause No. 45264, original filing	11,133			11,133	309	(18)	24
25	20% TDSIC Distribution revenue requirement deferred per the March 4, 2020 IURC order in Cause No. 45264, TDSIC 1	6,073			6,073	1,518	(19)	25

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
	2020 IURC order in Cause No. 45264, TDSIC 1	6,073			6,073	1,518	(19)	
26	20% TDSIC Transmission revenue requirement deferred per the March 4, 2020 IURC order in Cause No. 45264, TDSIC 1	$ 1,010			$ 1,010	$ 252	(19)	26
27	Total of rate base regulatory assets, agrees to RB9-WP1	$ 404,947	$ (124,202)	$ —	$ 280,745	$ 29,707		27
28	Net pro forma regulatory assets adjustment (See Schedule RB1, Line 8)			$ (124,202)				28
29	Eagle Valley forced outage- FAC 133S1 Settlement & Order, not included in rate base and amortized over 25 years (see Schedule RB4)	11,022			11,022	441	(20)	29
30	Foregone revenues deferred related to COVID-19 per the June 29, 2020 IURC order in Cause No. 45380-Phase 1	5,426	—	—	5,426	1,357	(21)	30
31	Total regulatory assets not included in rate base	$ 16,448	$ —	$ —	$ 16,448			31
32	Total pro forma amortization expense (Included in Schedule DEPR)					$ 31,505	(22)	32

(1) The pro forma annual amortization was calculated by dividing the original cost of $32,688,591 by the useful life of 31 years at August 31, 1995.
(2) The pro forma annual amortization was calculated by dividing the original post in service AFUDC on Petersburg assets by the useful by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets. HS7 carrying costs are amortized at the same level as approved in the prior rate case.
(3) The pro forma annual amortization was calculated by dividing the original deferred depreciation by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.
(4) The pro forma annual amortization was calculated by dividing the deferred depreciation for the NAAQS-DBA projects by a 10 year amortization based on the depreciation study and consistent with Petersburg Unit 2 assets.
(5) The pro forma annual amortization was calculated by dividing the deferred carrying charges for the NAAQS-DBA projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.
(6) The pro forma annual amortization was calculated by dividing the deferred depreciation for the CCR Bottom Ash projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.
(7) The pro forma annual amortization was calculated by dividing the deferred carrying charges for the CCR Bottom Ash projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.
(8) The pro forma annual amortization was calculated by dividing the deferred depreciation for the NAAQS-Other projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.
(9) The pro forma annual amortization was calculated by dividing the deferred carrying charges for the NAAQS-Other projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.
(10) The pro forma annual amortization was calculated by dividing the deferred depreciation for the Eagle Valley CCGT and the Harding Street 5 & 6 Refueling by the remaining useful life.
(11) The pro forma annual amortization was calculated by dividing the deferred post in-service AFUDC for the Eagle Valley CCGT and the Harding Street 5 & 6 Refueling by the remaining useful life.
(12) The pro forma annual amortization was calculated by dividing the electric vehicle deferred asset by a 10 year amortization period (agrees to prior rate case).
(13) The pro forma annual amortization was calculated by dividing the original deferred Harding Street 7 Preservation costs of $4,233,695.40 by a ten year amortization period (agrees to prior rate case).
(14) The pro forma annual amortization was calculated by dividing the deferred 20% HS7 Gas Conversion and NPDES Revenue Requirements by a 3 year amortization period.
(15) The pro forma annual amortization was calculated by dividing the deferred 20% NAAQS-DBA, CCR Bottom Ash, and NAAQS-Other Revenue Requirements by a 3 year amortization period.
(16) The pro forma annual amortization for Petersburg Unit 1 & 2 is equal to the depreciation in the Settlement Agreement in Cause No. 45502.
(16.1) Amortized over 10 years.
(17) The pro forma annual amortization was calculated by dividing the deferred depreciation for TDSIC by the useful life (36.3 years) as approved in the IURC Orders from Cause No. 45264, TDSIC 1.
(18) The pro forma annual amortization was calculated by dividing the deferred post in-service AFUDC for the TDSIC projects by the useful life (36.3 years) as approved in the IURC Orders in Cause No. 45264 TDSIC 1.
(19) The pro forma annual amortization was calculated by dividing the deferred 20% TDSIC Distribution and TDSIC Transmission Revenue Requirements by a 3 year amortization period.
(20) The pro forma annual amortization for the Eagle Valley outage repair capital expenditures was calculated by dividing the costs by a 25 year amortization period for the Settlement Agreement in IURC Cause No. 38703 FAC 133S1.
(21) The pro forma annual amortization for the COVID-19 deferral was calculated by dividing the deferral by a 3 year amortization period.
(22) See Financial Exhibit AESI-OPER, Schedule DEPR, Line 13.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB9.

AES Indiana

Statements of Electric Operating Income for the Twelve Months Ended December 31, 2022

Per Books and Jurisdictional Pro Forma at Present and Proposed Rates

(Thousands of Dollars)

Line No.		Twelve Months Ended 12/31/2022 Per Books (Col. 1)	At Present Rates Adjustments (Col. 2)	At Present Rates Pro Forma (Col. 3)	At Proposed Rates Adjustments (Col. 4)	At Proposed Rates Pro Forma (Col. 5)	Line No.
1	Operating revenues	$ 1,791,546	$ (219,947)	$ 1,571,599	$ 72,923	$ 1,644,522	1
	Operating expenses:						
2	Operation and maintenance expenses	1,242,330	(207,195)	1,035,135	387	1,035,522	2
3	Depreciation and amortization expense	272,093	30,336	302,428	—	302,428	3
4	Taxes-other than income taxes	33,464	(6,470)	26,994	—	26,994	4
5	Total operating expenses other than income taxes	1,547,886	(183,329)	1,364,558	387	1,364,945	5
6	Net operating income before income taxes	243,660	(36,618)	207,041	72,536	279,577	6
	Income taxes:						
7	Federal income taxes - current	31,385	(568)	30,817	14,486	45,303	7
8	State income taxes - current	8,168	(716)	7,452	3,554	11,006	8
9	Federal income taxes - deferred	(7,278)	(4,261)	(11,539)	—	(11,539)	9
10	State income taxes - deferred	125	(1,990)	(1,865)	—	(1,865)	10
11	Income tax credit adjustments	(3)	—	(3)	—	(3)	11
12	Total income taxes	32,398	(7,535)	24,862	18,040	42,902	12
13	Net utility operating income	$ 211,262	$ (29,083)	$ 182,179	$ 54,496	$ 236,675	13

AES Indiana
Summary of Electric Operating Revenue for the Twelve Months Ended December 31, 2022
Per Books and Pro Forma at Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Per Books (Col. 1)	At Present Rates Adjustments (1) (Col. 2)	At Present Rates Pro Forma (Col. 3)	At Proposed Rates Adjustments (2) (Col. 4)	At Proposed Rates Pro Forma (Col. 5)	Line No.
1	Residential revenues	$ 697,060	$ (40,260)	$ 656,800	$ 49,307	$ 706,107	1
2	Small commercial & industrial revenues	242,173	(6,605)	235,568	9,596	245,164	2
3	Large commercial & industrial revenues	643,606	(35,957)	607,649	15,541	623,190	3
4	Lighting	17,628	(98)	17,530	1,527	19,057	4
5	Electric vehicle public charging stations	30	—	30	—	30	5
6	Off-system sales	148,517	(119,905)	28,612	—	28,612	6
7	Capacity sales	11,750	(11,750)	—	—	—	7
8	Total sales of electric energy	1,760,764	(214,575)	1,546,189	75,971	1,622,160	8
	Other Electric Revenues						
9	Rents	3,368	(130)	3,238	—	3,238	9
10	Other customer charges	16,875	—	16,875	(3,048)	13,827	10
11	Miscellaneous revenue	10,539	(5,242)	5,297	—	5,297	11
12	Total other electric revenues	30,782	(5,372)	25,410	(3,048)	22,362	12
13	Total electric operating revenues (See Exhibit AESI-OPER, Sch. OPINC, Line 1)	$ 1,791,546	$ (219,947)	$ 1,571,599	$ 72,923	$ 1,644,522	13

(1) Adjustments shown on AES Indiana Financial Exhibit AESI-OPER, Schedule REV2
(2) Adjustments shown on AES Indiana Financial Exhibit AESI-OPER, Schedule REV10

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV1.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Adding Back Pro Forma at Present Rates Rider Revenues
to Achieve Total Retail Revenue Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Adjusted Basic Rate Revenue (1)	Add: Pro Forma at Present Rates Rider 6 Fuel Revenue (2)	Add: Pro Forma at Present Rates Rider 20 ECR Revenue (3)	Add: Pro Forma at Present Rates Rider 22 DSM Lost Revenue (4)	Sub-Total to Page 2	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	
1	Residential revenues	$ 573,833	$ 31,211	$ 507	$ 8,266	$ 613,817	1
2	Small commercial & industrial revenues	200,667	10,693	168	9,794	221,323	2
3	Large commercial & industrial revenues	519,334	37,022	514	6,333	563,203	3
4	Lighting	16,675	351	5	87	17,118	4
5	Electric vehicle public charging stations	30	—	—	—	30	5
6	Total	$ 1,310,540	$ 79,277	$ 1,194	$ 24,479	$ 1,415,490	6
7	Pro forma revenue adjustments		$ 79,277	$ 1,194	$ 24,479	$ 104,950	7

(1) From Schedule REV4, Column 6
(2) This amount represents normalized KWh sales multiplied by the proposed change in the base cost of fuel. See REV5-WP1.
(3) This amount reflects annualized ECR revenue for projects moving into base rates and therefore excludes the return AESI accrued on construction work in progress for its NAAQS-Other, projects during the test year. See REV5-WP2.
(4) This amount reflects the annualized lost revenues from DSM programs installed prior to the end of the test year moving into base rates. See REV5, WP3.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Adding Back Pro Forma at Present Rates Rider Revenues
to Achieve Total Retail Revenue Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Sub-Total from Page 1	Add: Pro Forma at Present Rates Rider 24 CAP Revenue (5)	Add: Pro Forma at Present Rates Rider 25 OSS Margins (6)	Add: Pro Forma at Present Rates Rider 26 RTO Revenue (7)	Add: Pro Forma at Present Rates Rider 3 TDSIC Revenue (8)	Total Electric Adjusted Basic Rate Revenue Pro Forma at Present Rates to Page 3	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
1	Residential revenues	$ 613,817	$ 12,879	$ (5,220)	$ 591	$ 20,448	$ 642,515	1
2	Small commercial & industrial revenues	221,323	4,275	(1,733)	196	6,787	230,848	2
3	Large commercial & industrial revenues	563,203	13,040	(5,285)	598	20,703	592,259	3
4	Lighting	17,118	124	(50)	6	197	17,395	4
5	Electric vehicle public charging stations	30	—	—	—	—	30	5
6	Total	$ 1,415,490	$ 30,318	$ (12,288)	$ 1,391	$ 48,135	$ 1,483,046	6
7	Pro forma revenue adjustments	$ 104,950	$ 30,318	$ (12,288)	$ 1,391	$ 48,135	$ 172,506	7

(5) This amount reflects the proposed change in the base cost of capacity net revenue and expense benchmark. See REV5-WP5.
(6) This reflects that the proposed change in the off-system sales ("OSS") margin benchmark. See REV5-WP6.
(7) This amount reflects the proposed change in the base cost of net MISO expense benchmark. See REV5-WP7.
(8) This amount reflects annualized TDSIC revenue for projects moving into base rates and therefore excludes the return AES Indiana accrued on construction work in progress for its TDSIC projects during the test year. See REV5-WP8.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Adding Back Pro Forma at Present Rates Rider Revenues
to Achieve Total Retail Revenue Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Total Electric Adjusted Basic Rate Revenue Pro Forma at Present Rates from Page 2	Add: Pro Forma at Present Rates Rider 20 ECR Revenue (9)	Add: Pro Forma at Present Rates Rider 22 DSM Revenue (10)	Add: Pro Forma at Present Rates Rider 21 Green Revenue (11)	Add: Pro Forma at Present Rates Rider 26 TDSIC Revenue (12)	Total Electric Adjusted Retail Revenue Pro Forma at Present Rates	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
1	Residential revenues	$ 642,515	$ —	$ 14,014	$ 271	$ —	$ 656,800	1
2	Small commercial & industrial revenues	230,848	—	4,651	69	—	235,567	2
3	Large commercial & industrial revenues	592,259	—	14,188	1,202	—	607,649	3
4	Lighting	17,395	—	135	—	—	17,530	4
5	Electric vehicle public charging stations	30	—	—	—	—	30	5
6	Total	$ 1,483,046	$ —	$ 32,988	$ 1,542	$ —	$ 1,517,577	6
7	Pro forma revenue adjustments (See Schedule REV2, Column 3)	$ 172,506	$ —	$ 32,988	$ 1,542	$ —	$ 207,036	7

(9) No environmental projects are remaining in the ECR, therefore no offsetting revenue has been included here.

(10) This amount reflects the test year DSM expenses (net of deferrals) recorded to expense accounts. See REV5-WP9.

(11) From Schedule REV3, Page 1, Column 5

(12) Pro forma test year expenses related to TDSIC projects in-service after 12/31/2022 net to zero, therefore no offsetting revenue has been included here.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV5.

AES Indiana
Electric Operating Revenue Adjustment
Taking Pro Forma at Present Rates
to Pro Forma at Proposed Rates
(Thousands of Dollars)

Line No.	Description	Revenue from Proposed Increase (Col. 1)	Line No.
1	Residential revenues	$ 49,307	1
2	Small commercial & industrial revenues	9,596	2
3	Large commercial & industrial revenues	15,541	3
4	Lighting	1,527	4
5	Electric vehicle public charging stations	—	5
6	Off-system sales	—	6
7	Capacity sales	—	7
8	Total sales of electric energy	75,971	8
	Other Electric Revenues		
9	Rents	—	9
10	Other customer charges	(3,048)	10
11	Miscellaneous revenue	—	11
12	Total other electric revenues	(3,048)	12
13	Total electric operating revenues	$ 72,923	13
14	Pro forma adjustment (See Schedule REV1, Column 4)	$ 72,923	14

Note: This exhibit agrees to AES Indiana Witness BR, Attachment 4, Page 2 of 2, Column O.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV10.

AES INDIANA
Summary of Pro Forma Adjustments to Electric Operation and Maintenance Expense for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Exhibit AESI-OPER Adjustment Schedule Reference	Pro Forma Adjustments: Total Electric At Present Rates	Pro Forma Adjustments: Total Electric At Proposed Rates	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1					1
2	Cost of fuel and purchased power	OM2	$ (226,079)	$ —	2
3	Capacity costs	OM3	17,238	—	3
4	Off-system sales power production costs	OM4	(14,503)	—	4
5	Generation consumables	OM5	(10,662)	—	5
6	Transportation expenses	OM6	(603)	—	6
7	Non-outage operating and maintenance costs	OM7	(13,517)	—	7
8	Seasonal NOx emission allowance expense	OM8	(914)	—	8
9	Obsolete/damaged materials and supplies inventory write-off expense	OM9	(634)	—	9
10	Non-jurisdictional MISO MTEP operating and maintenance expenses	OM10	(953)	—	10
11	Storm expenses	OM11	(2,533)	—	11
12	Vegetation management costs	OM12	10,214	—	12
13	MISO non-fuel costs	OM13	369	—	13
14	MISO deferred expense amortization	OM14	—	—	14
15	Wages of AES Indiana and AES U.S. Services, LLC employees	OM15	14,239	—	15
16	Employer insurance benefits of AES Indiana and AES U.S. Services, LLC employees	OM16	1,834	—	16
17	Pension expense and OPEB	OM17	13,580	—	17
18	ACE Project	OM18	8,127	—	18
19	Image-building advertising costs	OM19	(2,205)	—	19
20	Injuries and damages expense	OM20	235	—	20
21	Amortization of rate case expense	OM21	750	—	21
22	Miscellaneous expense adjustments	OM22	(2,772)	—	22
23	AES U.S. Services, LLC occupancy and non-labor costs	OM23	(855)	—	23
24	ECR, TDSIC Tracker Items	OM24	(922)	—	24
25	Property and other casualty insurance expense	OM25	4,864	—	25
26	Write off of preliminary survey and investigation charges	OM26	(325)	—	26
27	Uncollectible accounts expense	OM27	(1,626)	279	27
28	Public utility fee	OM28	628	108	28
29	Total pro forma adjustments (See Exhibit AESI-OPER, Schedule OPINC, Line 2, Columns 3 and 5, respectively)		$ (207,026)	$ 387	29

AES Indiana
Pro Forma Adjustment to Cost of Fuel and Purchased Power
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars, Except Base Cost of Fuel Increment)

The following pro forma adjustment reflects the change in total electric cost of fuel and purchased power, taking into consideration changes in pro forma MWh sales, power purchases, and power sales.

Line No.		(Col. 1)	(Col. 2)	Line No.
	MWh Source			
1	Coal and oil generation		6,316,299	1
2	Gas generation		9,641,261	2
3	Other generation- internal combustion			3
	Purchases through MISO:			
4	Wind purchase power agreement (PPA) purchases		747,509	4
5	Non-Wind PPA market purchases		394,025	5
6	Purchased power other than MISO (solar)		144,205	6
	Less:			
7	Energy losses and company use		604,181	7
8	Inter-System sales through MISO		3,619,393	8
9	Total MWh source		13,019,725	9
	Fuel Cost $			
10	Coal and oil generation		$ 184,752	10
11	Gas generation		319,912	11
12	Other generation- internal combustion			12
	Purchases through MISO:			
13	Wind purchase power agreement purchases		51,237	13
14	Non-Wind PPA market purchases		14,509	14
15	MISO components of cost of fuel		26,821	15
16	Purchased power other than MISO (solar)		23,503	16
	Less:			
17	Inter-System sales through MISO		107,200	17
18	Transmission losses		5,417	18
19	Pro forma total retail electric cost of fuel		508,117	19
20	Actual total electric coal, oil, gas, and purchased power costs for the twelve months ended December 31, 2022		734,196	20
21	Pro forma adjustment to retail fuel cost (See Schedule OM1)		$ (226,079)	21
	Breakout of retail and wholesale fuel costs			
22	Pro forma total retail electric cost of fuel (from Line 19)	$ 508,117		22
23	Actual retail fuel cost	(657,969)		23
24	Pro forma adjustment for retail fuel cost	(149,852)		24
25	Reclassify actual off-system sales fuel cost (See Schedule REV6)	(76,227)		25
26	Total pro forma adjustment to fuel costs	$ (226,079)		26
27	New base cost of fuel per kWh (line 20 / line 9)		$ 0.039027	27

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM2.

AES Indiana
Pro Forma Adjustment to
Generation Consumables Variable Expenses
(Thousands of Dollars)

The following pro forma adjustment is to reflect non-labor changes to the retail cost of generation consumables.

Line No.		Pro Forma O & M (Col. 1)	Actual Generating Unit Consumables Cost Per Books for the Twelve Months Ended December 31, 2022 (Col. 2)	Pro Forma Adjustment (Col. 3)	Line No.
1	Harding Street Generating Station	$ 1,029	$ 649	$ 380	1
2	Eagle Valley CCGT	1,198	598	600	2
3	Petersburg	13,287	16,879	(3,592)	3
4	Petersburg Unit 2	—	8,050	(8,050)	4
5	Total pro forma adjustment (See Schedule OM1)	$ 15,514	$ 26,176	$ (10,662)	5

AES Indiana
Pro Forma Adjustment to Distribution Vegetation Management Costs
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

vegetation management costs.

Line No.		Pro Forma Costs	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Total pro forma expense adjustment (See Schedule OM1)	$ 25,247	$ 15,033	$ 10,214	1

AES Indiana Workpaper OM12.

AES Indiana
Pro Forma Adjustment to Operation and Maintenance Expenses for Wages of AES Indiana and AES U.S. Services, LLC (AES Services) Employees
(Thousands of Dollars)

The following adjustment represents the net impact of changes to AES Indiana and AES U.S. Services, LLC (AES Services) labor costs

Line No.		Total Electric Per Books	Pro Forma	Adjustments	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Labor costs (AES Indiana employees)	$ 113,540	$ 124,565	$ 11,025	1
2	Labor costs (from AES Services)	19,760	22,974	3,213	2
3	Total labor, AES Indiana and AES Services costs	$ 133,300	$ 147,539		3
4	Pro forma adjustment (See Schedule OM1)			$ 14,239	4

AES Indiana
Pro Forma Adjustment to Operations and Maintenance Expense for the ACE Project
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment adjusts the on going O&M related to the ACE Project.

Line No.		Pro Forma ACE O&M Expense	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	ACE O&M	$ 9,322	$ 1,195	$ 8,127	1
2	Total ACE O&M	$ 9,322	$ 1,195	$ 8,127	2

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM18.

AES Indiana
Pro Forma Adjustment to Amortization of Rate Case Expense
(Thousands of Dollars)

It is estimated that the following costs will be incurred in the preparation and presentation of AES Indiana's current Petition to the Commission. AES Indiana considers it reasonable to amortize these costs over three years.

Line No.		Amortization Period (Col. 1)	Cost (Col. 2)	Total (Col. 3)	Line No.
1	Cost of depreciation and demolition studies:				1
2	Depreciation		$ 100		2
3	Demolition		180		3
4	Total projected cost of depreciation and demolition studies			$ 280	4
5	All other rate case expenses:				5
6	Legal		$ 1,900		6
7	Fair Return		75		7
8	Weather Normalization		178		8
9	Rate Design		461		9
10	Line Loss Study		80		10
11	Accounting and Tax Consulting		100		11
12	Configuration		296		12
13	Other - (e.g. Additional Witness/Consulting Support, Postage)		1,615		13
14	Total projected cost of all other rate case expenses			$ 4,705	14
15	Total pro forma cost of 2023 rate case expenses			$ 3,000	15
16	Pro forma annual amortization of rate case expenses	4 years		$ 750	16
17	Less: Per books amortization during the twelve months ended December 31, 2022			—	17
18	Total pro forma adjustment (See Schedule OM1)			$ 750	18

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM21.

AES Indiana 2023 Basic Rate Case
Settlement Agreement Attachment B
Schedule OM22-S

AES Indiana
Pro Forma Adjustments
Due to Miscellaneous Expense Items
(Thousands of Dollars)

This schedule removes items not deemed to be reasonably necessary to provide reliable electric service and also reflects

adjustments to bring certain miscellaneous test year expenses to the current experienced rate of expense as of the end of the test year.

Line No.		Pro Forma Adjustments (Col. 1)	(Col. 2)	Line No.
1	Production - Operations			1
2	Operation of Steam Power Generation	$ (44)		2
3	Maintenance of Steam Plant	(10)		3
	Other Power Production	(15)		
4			$ (69)	4
5	Transmission & Distribution			5
6	Transmission operation and maintenance expenses	$ (16)		6
7	Distribution operation and maintenance expenses	(524)		7
8			$ (540)	8
9	Customer Accounts		(3)	9
10	Customer Service & Informational		(6)	10
11	Administrative & General			11
12	Office supplies and expenses	$ (203)		12
12	Outside services employed	354		12
13	Employee Pensions and Benefits	(5)		13
14	Miscellaneous general expenses	(2,293)		14
15	Maintenance of General Plant	(7)		15
16			(2,154)	16
17	Pro forma adjustment (See Schedule OM1)		$ (2,772)	17
	Summary of pro forma adjustment			
18	Miscellaneous expense adjustments		(804)	18
19	Run-rate adjustment		(1,968)	19
20	Total pro forma adjustment (agrees to line 17 above)		$ (2,772)	20

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM22.

AES Indiana
Pro Forma Adjustments to Uncollectible Accounts Expense
(Thousands of Dollars)

The following adjustments reflect the application of the experience rate of uncollectible accounts to the respective pro forma electric revenues.

Line No.		Total Electric At Present Rates (Col. 1)	Total Electric At Proposed Rates (Col. 2)	Supporting AES Indiana Financial Exhibit Reference (Col. 3)	Line No.
1	Electric operating revenues for the twelve months ended December 31, 2022	$ 1,571,600	$ 1,644,690	AESI-OPER, Sch. OPINC, Line 1, Cols. 4 and 6	1
2	Less: Off-system sales	28,612	28,612	AESI-OPER, Sch. REV1, Line 6, Cols. 3 and 5	2
3	Less: Rents from electric property	3,238	3,238	AESI-OPER, Sch. REV1, Line 9, Cols. 3 and 5	3
4	Less: Capacity sales	—	—	AESI-OPER, Sch. REV1, Line 7, Cols. 3 and 5	4
5	Less: Miscellaneous electric revenue	5,297	5,297	AESI-OPER, Sch. REV1, Line 11, Cols. 3 and 5	5
6	Net	$ 1,534,453	$ 1,607,543		6
7	Uncollectible accounts experience rate	0.3814 %			7
8	Pro forma uncollectible electric accounts expense	$ 5,852	$ 6,131		8
9	Amount charged to total electric operating expense for the twelve months ended December 31, 2022	7,478			9
10	Pro forma adjustment at present rates	$ (1,626)		(See Exhibit AESI-OPER, Sch. OM1, Column 1)	10
11	Less: Pro forma electric at present rates expense		5,852		11
12	Pro forma adjustment at proposed rates		$ 279	(See Exhibit AESI-OPER, Sch. OM1, Column 2)	12

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM27.

AES Indiana
Pro Forma Adjustments to Public Utility Fee
(Thousands of Dollars)

The following adjustments reflect the application of the public utility fee, increased by the current billing factor, to the respective pro forma electric revenues.

Line No.	Description	Total Electric At Present Rates (Col. 1)	Total Electric At Proposed Rates (Col. 2)	Supporting AES Indiana Financial Exhibit Reference (Col. 3)	Line No.
1	Electric operating revenues for the twelve months ended December 31, 2022	$ 1,571,600	$ 1,644,690	AESI-OPER, Sch. OPINC, Line 1, Cols. 4 and 6	1
2	Less : Capacity Sales	(11,750)	(11,750)	AESI-OPER, Sch. REV1, Line 7, Cols. 3 and 5	2
3	Less: Off-system sales	28,612	28,612	AESI-OPER, Sch. REV1, Line 6, Cols. 3 and 5	3
4	Less: Rents	3,238	3,238	AESI-OPER, Sch. REV1, Line 9, Cols. 3 and 5	4
5	Less: Other customer charges	16,875	16,875	AESI-OPER, Sch. REV1, Line 10, Cols. 3 and 5	5
6	Less: Miscellaneous electric revenues	5,297	5,297	AESI-OPER, Sch. REV1, Line 11, Cols. 3 and 5	6
7	Less: Uncollectible accounts expense	5,852	6,131	AESI-OPER, Sch. OM27, Line 8, Cols. 1 and 2	7
8	Net electric operating revenue subject to public utility fee	$ 1,523,476	$ 1,596,287		8
9	Effective public utility fee rate	0.001468			9
10	Pro forma public utility fee	$ 2,236	$ 2,344		10
11	Fee charged to total electric operating expense during the twelve months ended December 31, 2022	1,608			11
12	Pro forma adjustment at present rates	$ 628		(See Exhibit AESI-OPER, Sch. OM1, Column 1)	12
13	Less: Pro forma electric at present rates expense		2,236		13
14	Pro forma adjustment at proposed rates		$ 108	(See Exhibit AESI-OPER, Sch. OM1, Column 2)	14

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM28.

AES Indiana

Pro Forma Adjustment to Total Electric at Present Rates to Reflect the Annual Provision for Depreciation and Amortization Expense for the Twelve Month Period Ended December 31, 2022

Applying Proposed Depreciation and Amortization Rates to Pro Forma Original Cost Rate Base

(Thousands of Dollars)

Line No.		Functional Classification Intangible Plant (Col. 1)	Systems Software (Col. 2)	Production Plant (Col. 3)	Transmission Plant (Col. 4)	Distribution Plant (Col. 5)	General Plant (Col. 6)	Total (Col. 7)	Line No.
1	Total electric utility plant in service per books (1)	$ 46	$ 153,606	$ 4,166,085	$ 461,042	$ 2,036,697	$ 260,172	$ 7,077,649	1
2	Less: Asset retirement obligation asset (2)			(195,718)	(30)	(235)	(693)	(196,676)	2
3	Less: Fully depreciated utility plant		(78,784)	(4,710)				(83,494)	3
4	Less: Non-depreciable assets included above - land and other	(46)		(3,672)	(546)	(3,621)	(3,775)	(11,660)	4
5	Total depreciable assets in service per books at December 31, 2022	$ —	$ 74,822	$ 3,961,985	$ 460,466	$ 2,032,841	$ 255,705	6,785,819	5
6	Less: Non-jurisdictional plant-in-service (3)				$ (20,788)			(20,788)	6
7	Add: ACE Project (4)		$ 94,071					94,071	7
8	Less: Pete Unit 2 and 1&2 Shared Asset Retirements (5)			$ (501,630)				(501,630)	8
9	Less: EV CCGT Forced Outage (5)			$ (11,112)				(11,112)	9
10	Total depreciable assets	$ —	$ 168,893	$ 3,449,242	$ 439,678	$ 2,032,841	$ 255,705	6,346,359	10
11	Pro forma depreciation and amortization	$ —	$ 20,248	$ 192,067	$ 9,162	$ 36,790	$ 12,732	270,999	11
12	Add: Plant acquisition adjustment amortization (6)							15	12
13	Add: Amortization of regulatory assets on AESI-RB, Schedule RB9 (7)							31,505	13
14	Total pro forma depreciation and amortization expense							$ 302,519	14
15	Less: regulatory asset amortization charges to FERC 923 for the twelve months ended December 31, 2022.							91	15
16	Less: Total depreciation and amortization expense charged to depreciation and amortization expense for the twelve months ended December 31, 2022 (8)							272,093	16
17	Pro forma adjustment (See AESI-OPER, Schedule OPINC, Line 3, Column 3)							$ 30,336	17

(1) See AESI-RB, Schedule RB2, Line 9

(2) See AESI-RB, Schedule RB6, Line 7

(3) See AESI-RB, Schedule RB5, Line 7

(4) See AESI-RB, Schedule RB3, Line 3

(5) See AESI-RB, Schedule RB4, Line 9

(6) Reflects a 33-year amortization period, the estimated remaining useful life of the asset at the time of the acquisition.

(7) See AESI-RB, Schedule RB9 Page 4 of 5, Line 32

(8) See AESI-OPER, Schedule OPINC, Line 3, Column 2

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper DEPR.

AES Indiana
Summary of Taxes Other than Income Taxes for the Twelve Months Ended December 31, 2022
Per Books and Pro Forma at Present and Proposed Rates
(Thousands of Dollars)

Line No.		Adjustment Shown on AESI Financial Exhibit AESI-OPER	Total Electric Per Books	Total Electric At Present Rates Adjustments	Pro Forma	Total Electric At Proposed Rates Adjustments	Pro Forma	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
1	Real estate and personal property taxes	Sch. OTX2	$ 12,620	$ 3,369	$ 15,989	$ —	$ 15,989	1
2	Payroll taxes	Sch. OTX3	9,014	1,257	10,272	—	10,272	2
3	Indiana utility receipts tax	Sch. OTX4	11,096	(11,096)	—	—	—	3
4	Miscellaneous taxes		733	—	733	—	733	4
5	Total taxes other than income taxes (See AESI Financial Exhibit AESI-OPER, Schedule OPINC, Line 4)		$ 33,464	$ (6,470)	$ 26,994	$ —	$ 26,994	5

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OTX1.

AES Indiana
Pro Forma Adjustment to Reflect the Change in
Payroll Taxes Applicable to Pro Forma Wage Adjustments and Changes in Tax Rates
Chargeable to Operation and Maintenance Expense
(Thousands of Dollars)

The following adjustment represents the net impact of changes to AESI and AES U.S. Services, LLC (AES Services) payroll tax costs

Line No.		Total Electric Per Books	Pro Forma	Adjustments	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Payroll Tax costs (AESI employees)	$ 7,621	$ 8,664	$ 1,043	1
2	Payroll Tax costs (from AES Services)	1,394	1,608	214	2
3	Total Payroll Tax, AESI and AES Services costs	$ 9,014	$ 10,272		3
4	Pro forma adjustment (See Schedule OM1)			$ 1,257	4

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OTX3.

AES Indiana
Determination of Interest Expense for Interest Synchronization
(Thousands of Dollars)

Line No.		Total Company Capitalization (Col. 1)		Percent of Total (Col. 2)	Cost (Col. 3)		Total Weighted Cost (Col. 4)	Original Cost Total Electric Rate Base (Col. 5)		Total Electric Synchronized Interest (Col. 6)	Line No.
1	Long-Term Debt	$ 2,153,036	(1)	49.15 %	4.90 %	(1)	2.41 %	$ 3,455,111	(3)	$ 83,268	1
2	Preferred Equity	—		— %							2
3	Common Equity	1,943,109	(2)	44.36 %							3
4	Prepaid Pension Asset (net of OPEB liability)	(133,100)	(2)	(3.04)%							4
5	Deferred Income Taxes	382,560	(2)	8.73 %							5
6	Post 1970 ITC	24	(2)	0.00 %							6
7	Customer Deposits	35,097	(2)	0.80 %							7
8		$ 4,380,726		100.00 %						$ 83,268	8

(1) See AESI-CC, Schedule CC1
(2) See AESI-CC, Schedule CC2
(3) See AESI-RB, Schedule RB1, Column 6, Line 9

AES Indiana
Comparison of Current and Proposed Pro Forma Revenues

Line No.	Rate Class	Rate Code	Current Revenue [1]	Unmitigated Proposed Revenue [1]	Mitigated Proposed Revenue [1]	Increase: Unmitigated - Current	Increase: Mitigated [2]	**Increase: Mitigated [3]**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 656,799,989	$ 745,741,742	$ 706,180,999	$ 88,941,753	$ 49,381,011	**7.52%**
2	Secondary Service (Small) (Rate SS)	SS	174,117,001	157,642,105	178,083,490	(16,474,896)	3,966,489	**2.28%**
3	Municipal Device (Rate MD)	MD	362,488	219,842	236,010	(142,646)	(126,479)	**-34.89%**
4	Electric Space Conditioning-Secondary Service (Rate SH)	SH	59,181,354	63,102,989	64,945,731	3,921,636	5,764,378	**9.74%**
5	Electric Space Conditioning-Schools (Rate SE)	SE	1,734,466	1,504,830	1,734,466	(229,636)	-	**0.00%**
6	Water Heating-Controlled Service (Rate CB/CW)	CB	47,154	74,875	51,431	27,720	4,277	**9.07%**
7	Water Heating-Uncontrolled Service (Rate UW)	UW	125,346	142,541	137,756	17,194	12,409	**9.90%**
8	Secondary Service (Large) - (Rate SL)	SL	349,814,896	342,343,654	356,796,627	(7,471,242)	6,981,731	**2.00%**
9	Primary Service (Large) - (Rate PL)	PL	105,592,169	109,427,425	112,777,840	3,835,256	7,185,672	**6.81%**
10	Process Heating (Rate PH)	PH	2,708,602	2,793,847	2,862,205	85,244	153,603	**5.67%**
11	High Load Factor (Rate HL-1) (Primary Distribution)	HL1	113,099,048	111,440,758	114,564,474	(1,658,290)	1,465,425	**1.30%**
12	High Load Factor (Rate HL-2) (Sub transmission)	HL2	16,299,458	14,752,087	16,166,333	(1,547,371)	(133,125)	**-0.82%**
13	High Load Factor (Rate HL-3) (Transmission)	HL3	20,134,603	19,169,021	20,087,442	(965,582)	(47,162)	**-0.23%**
1	Automatic Protective Lighting (APL)	APL	8,808,226	11,758,070	9,680,241	2,949,844	872,014	**9.90%**
2	Municipal Lighting (MU)	MU1	$ 8,721,553	$ 13,567,557	$ 9,376,296	$ 4,846,005	$ 654,744	**7.51%**
3	**TOTAL SYSTEM**		**$ 1,517,546,354**	**$ 1,593,681,342**	**$ 1,593,681,342**	**$ 76,134,987**	**$ 76,134,987**	5.02%

[1] From ACOSS.
[2] Col. (E) - (C) + (G)

Line No.	Rate Class		Current Revenue [1]	Unmitigated Proposed Revenue [1]	Mitigated Proposed Revenue [1]	Increase: Unmitigated - Current	Increase: Mitigated [2]
	(A)	(B)	(C)	(D)	(E)	(F)	(H)
1	Residential		656,799,989	745,741,742	706,180,999	$ 88,941,753	$ 49,381,011
2	Small C&I		235,567,810	222,687,181	245,188,884	$ (12,880,628)	$ 9,621,074
3	Large C&I		607,648,777	599,926,791	623,254,921	$ (7,721,986)	$ 15,606,144
4	Lighting		17,529,779	25,325,628	19,056,537	$ 7,795,849	$ 1,526,758
5	**TOTAL SYSTEM**		**$ 1,517,546,354**	**$ 1,593,681,342**	**$ 1,593,681,342**	**$ 76,134,987**	**$ 76,134,987**

AES Indiana

Demand Factors Used in Rate Adjustment Mechanisms

From AES Witness BR Workpaper 1.0C-R

	ECR			OSS, CAP, RTO		
	Current	Proposed	Change	Current	Proposed	Change
Demand Allocation Factors based on 12 CP Generation in COSS						
Residential	**42.48%**	**44.00%**	1.52%	**42.48%**	**44.00%**	1.52%
Small C&I	**14.10%**	**14.39%**	0.29%	**14.10%**	**14.39%**	0.29%
Large C&I - PL						
Large C&I - HL						
Large C&I - Primary	**17.62%**	**17.31%**	-0.31%	**17.62%**	**17.31%**	-0.31%
Large C&I - SL & PH						
Large C&I - Secondary	**25.39%**	**24.06%**	-1.33%	**25.39%**	**24.06%**	-1.33%
Large C&I - Total	43.01%	41.37%	-1.64%	43.01%	41.37%	-1.64%
Lighting	**0.41%**	**0.24%**	-0.17%	**0.41%**	**0.24%**	-0.17%
Total	100.00%	100.00%	0.00%	100.00%	100.00%	0.00%

AES Indiana
Revenue Percentages
Test Year Ended December 31, 2022

TDSIC Allocation Factors

(A) Rate Class	(B) Rate Code(s)		(C) Total Revenue Requirement	(D) Percent		(E) Class Revenue Allocation - Transmission	(F) Percent		(G) Class Revenue Allocation - Distribution	(H) Percent
Residential	RS, RC, RH	$	706,180,999	44.31%	$	38,224,856	40.05%	$	140,955,760	59.41%
Small C&I	SS, SH, SE, CB, UW		245,188,884	15.39%		15,546,390	16.29%		36,428,882	15.35%
Large C&I - Secondary	SL, PH		359,658,832	22.57%		24,219,723	25.38%		37,097,243	15.64%
Large C&I - Primary	PL, HL		263,596,089	16.54%		17,271,531	18.10%		21,931,355	9.24%
Lighting	APL, MU1	$	19,056,537	1.20%	$	168,958	0.18%	$	833,604	0.35%
TOTAL SYSTEM		$	1,593,681,342	100.00%	$	95,431,458	100.00%	$	237,246,843	100.00%

Rate Code Allocations

(A) Rate Class	(B) Rate Code		(C) Total Revenue Requirement	(D) Percent		(E) Class Revenue Allocation - Transmission	(F) Percent		(G) Class Revenue Allocation - Distribution	(H) Percent
Residential Service (Rate RS) - Codes RS, RC, RH	RS	$	706,180,999	44.31%	$	38,224,856	40.05%	$	140,955,760	59.41%
Secondary Service (Small) (Rate SS)	SS		178,083,490	11.17%		10,961,572	11.49%	$	26,468,055	11.16%
Municipal Device (Rate MD)	MD		236,010	0.01%		5,224	0.01%	$	97,416	0.04%
Electric Space Conditioning-Secondary Service (Rate SH)	SH		64,945,731	4.08%		4,457,232	4.67%	$	9,595,668	4.04%
Electric Space Conditioning-Schools (Rate SE)	SE		1,734,466	0.11%		114,538	0.12%	$	229,213	0.10%
Water Heating-Controlled Service (Rate CB/CW)	CB		51,431	0.00%		1,516	0.00%	$	11,312	0.00%
Water Heating-Uncontrolled Service (Rate UW)	UW		137,756	0.01%		6,309	0.01%	$	27,217	0.01%
Secondary Service (Large) - (Rate SL)	SL		356,796,627	22.39%		24,049,243	25.20%	$	36,609,053	15.43%
Primary Service (Large) - (Rate PL)	PL		112,777,840	7.08%		7,614,773	7.98%	$	11,261,850	4.75%
Process Heating (Rate PH)	PH		2,862,205	0.18%		170,480	0.18%	$	488,190	0.21%
High Load Factor (Rate HL-1) (Primary Distribution)	HL1		114,564,474	7.19%		7,214,254	7.56%	$	10,669,505	4.50%
High Load Factor (Rate HL-2) (Sub transmission)	HL2		16,166,333	1.01%		1,100,088	1.15%	$	-	0.00%
High Load Factor (Rate HL-3) (Transmission)	HL3		20,087,442	1.26%		1,342,417	1.41%	$	-	0.00%
Automatic Protective Lighting - APL	APL		9,680,241	0.61%		103,618	0.11%	$	503,085	0.21%
Municipal Lighting MU-1	MU1	$	9,376,296	0.59%	$	65,340	0.07%	$	330,518	0.14%
TOTAL SYSTEM		$	1,593,681,342	100.00%	$	95,431,458	100.00%	$	237,246,843	100.00%

AES Indiana
MU Lighting Rate Design

Code	Description	Inventory (Light Count)	Proposed Annual Rate	Proposed Revenue
(A)	(B)	(C)	(F)	(G)
MU				
	Company Installed, Owned, and Maintained (MU-1)			
1	1000 WATT MV - OVERHEAD	1	$371.64	$372
2	1000 WATT MV - TRAFFIC COLUMN	0	$334.32	$0
3	1000 WATT MV - METAL COLUMN	3	$517.80	$1,553
4	400 WATT MV - OVERHEAD	16	$197.28	$3,156
5	400 WATT MV - TRAFFIC COLUMN	0	$179.52	$0
6	400 WATT MV - METAL COLUMN	144	$265.56	$38,241
7	175 WATT MV - OVERHEAD	446	$131.16	$58,497
8	175 WATT MV - TRAFFIC COLUMN	0	$121.56	$0
9	175 WATT MV - METAL COLUMN	670	$206.04	$138,047
10	175 W MV - POST TOP	476	$200.88	$95,619
11	175 W MV - POST TOP WASH	189	$306.72	$57,970
12	400 WATT HPS - OVERHEAD	240	$227.88	$54,691
13	400 WATT HPS - TRAFFIC COLUMN	65	$227.88	$14,812
14	400 WATT HPS - METAL COLUMN	552	$373.92	$206,404
15	250 WATT HPS - OVERHEAD	505	$181.32	$91,567
16	250 WATT HPS - TRAFFIC COLUMN	36	$181.32	$6,528
17	250 WATT HPS - METAL COLUMN	619	$250.92	$155,319
18	150 WATT HPS - OVERHEAD	491	$140.28	$68,877
19	150 WATT HPS - TRAFFIC COLUMN	7	$140.28	$982
20	150 WATT HPS - METAL COLUMN	472	$212.28	$100,196
21	100 WATT HPS - OVERHEAD	796	$117.72	$93,705
22	100 WATT HPS - TRAFFIC COLUMN	1	$117.72	$118
23	100 WATT HPS - METAL COLUMN	517	$192.60	$99,574
24	100 W HPS - POST TOP	5,857	$191.64	$1,122,435
25	100 W HPS - POST TOP WASH	1,703	$294.48	$501,499
26	150 W HPS- POST TOP BALL	21	$233.40	$4,901
27	150 W HPS - POST TOP WASH	3,037	$340.56	$1,034,281
28	3-150 WATT HPS-1 COLUMN CLUSTER W/BALAST	0	$562.20	$0
29	3-150 WATT HPS-2 COLUMN CLUSTER N/BALAST	0	$562.20	$0
30	3-150 WATT HPS-2 COLUMN CLUSTER W/BALAST	0	$562.20	$0
32	1-150 & 4-100 WATT HPS - CLUSTER	1	$783.12	$783
33	400 WATT HPS-METAL COLUMN-PAINTED BRONZE	74	$405.12	$29,979
34	400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	8	$233.04	$1,864
35	250 WATT HPS-METAL COLUMN-PAINTED BRONZE	1	$282.24	$282
37	175 WATT MV - FIBERGLASS COLUMN	6	$196.80	$1,181
38	100 WATT HPS - FIBERGLASS COLUMN	103	$183.24	$18,874
39	150 WATT HPS - FIBERGLASS COLUMN	155	$202.80	$31,434
40	250 WATT HPS - FIBERGLASS COLUMN	124	$241.68	$29,968
41	400 WATT HPS - FIBERGLASS COLUMN	159	$349.08	$55,504
42	400 WATT MH SHOEBOX - FIBERGLASS COLUMN	103	$320.40	$33,001
43	2-400 WATT MH SHOEBOX-FIBERGLASS COLUMN	48	$455.16	$21,848
44	175 WATT MV UPASS 4100HRS - WALL MOUNTED	0	$156.96	$0
45	150 WATT HPS UPASS 4100HRS -WALL MOUNTED	192	$180.84	$34,721
46	250 W HPS - SHOEBOX	10	$252.48	$2,525
48	2-250 W HPS-SHOEBOX	0	$323.88	$0
50	400 WATT HPS UPASS 8760HRS WALL MOUNTED	85	$422.76	$35,935
51	150 WATT HPS UPASS 8760HRS WALL MOUNTED	101	$242.88	$24,531
65	400 W HPS - SHOEBOX	43	$314.88	$13,540
66	2-400 W HPS-SHOEBOX	15	$444.48	$6,667
101	400 WATT METAL HALIDE - METAL COLUMN	0	$372.60	$0

AES Indiana
MU Lighting Rate Design

184 EXCESS MATERIAL FOR CIRCLE CENTRE MALL	1	$6,304.32	$6,304
185 PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	47	$812.16	$38,172
187 TWIN 80W LED POST TOP	53	$792.96	$42,027
200 LED COBRA HEAD 5000-6000 LUMENS	1,226	$213.63	$261,905
201 LED COBRA HEAD 6500-7500 LUMENS	462	$219.31	$101,321
202 LED COBRA HEAD 12500-13500 LUMENS	460	$266.64	$122,654
203 LED COBRA HEAD 20000-21500 LUMENS	171	$308.63	$52,776
204 LED AREA LIGHT 11500-16500 LUMENS	0	$287.71	$0
205 LED AREA LIGHT 21000-26000 LUMENS	31	$321.02	$9,952
206 LED TRAD. POST TOP 6000-7500 LUMENS	336	$262.09	$88,063
207 LED TWIN WASH POST TOP 2 @ 6000-7500-LT	35	$632.93	$22,153
208 LED WASH POST TOP 6000-7500 LUMENS	138	$350.10	$48,313
212 400 WATT HPS - OVERHEAD	4	$451.68	$1,807
213 400 WATT HPS - TRAFFIC COLUMN	0	$410.16	$0
214 400 WATT HPS - METAL COLUMN	32	$579.12	$18,532
215 250 WATT HPS - OVERHEAD	25	$389.04	$9,726
216 250 WATT HPS - TRAFFIC COLUMN	0	$347.40	$0
217 250 WATT HPS - METAL COLUMN	42	$516.48	$21,692
218 150 WATT HPS - OVERHEAD	12	$346.80	$4,162
219 150 WATT HPS - TRAFFIC COLUMN	0	$305.40	$0
220 150 WATT HPS - METAL COLUMN	1	$474.24	$474
221 100 WATT HPS - OVERHEAD	27	$317.64	$8,576
222 100 WATT HPS - TRAFFIC COLUMN	0	$276.00	$0
223 100 WATT HPS - METAL COLUMN	31	$444.96	$13,794
224 100 W HPS - POST TOP	211	$304.80	$64,313
225 100 W HPS - POST TOP WASH	117	$406.20	$47,525
226 150 W HPS- POST TOP BALL	0	$385.08	$0
227 150 W HPS - POST TOP WASH	247	$429.00	$105,963
228 12' FG TRAD COL PAIRED W/LT	336	$88.20	$29,635
232 1-150 & 4-100 WATT HPS - CLUSTER	0	$962.16	$0
233 400 WATT HPS-METAL COLUMN-PAINTED BRONZE	0	$604.80	$0
234 400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	0	$347.76	$0
235 250 WATT HPS-METAL COLUMN-PAINTED BRONZE	0	$552.00	$0
236 250 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	0	$285.12	$0
237 12' FG FLUTED COL CUST BASE PAIRED W/LT	0	$178.80	$0
238 100 WATT HPS - FIBERGLASS COLUMN	2	$359.88	$720
239 150 WATT HPS - FIBERGLASS COLUMN	13	$393.48	$5,115
240 250 WATT HPS - FIBERGLASS COLUMN	0	$435.72	$0
241 400 WATT HPS - FIBERGLASS COLUMN	1	$498.24	$498
242 14' AL FLUTED COL CUST BASE PAIRED W/LT	52	$206.76	$10,752
243 14 FG FLUTED COL DIRECT BURY PAIRED W/LT	14	$181.56	$2,542
244 14 FG SMOOTH COL DIRECT BURY PAIRED W/LT	88	$156.12	$13,739
245 150 WATT HPS UPASS 4100HRS -WALL MOUNTED	0	$285.60	$0
246 250 W HPS - SHOEBOX	0	$431.52	$0
248 2-250 W HPS-SHOEBOX	0	$494.16	$0
250 400 WATT HPS UPASS 8760HRS WALL MOUNTED	0	$539.76	$0
251 150 WATT HPS UPASS 8760HRS WALL MOUNTED	0	$330.84	$0
254 AL COL W/BASE PAIRED W/LT	122	$220.92	$26,952
255 AL COL ON CUST OWNED BASE PAIRED W/LT	1	$123.12	$123
265 400 W HPS - SHOEBOX	1	$494.88	$495
266 2-400 W HPS-SHOEBOX	0	$710.88	$0
269 AL COL BZ W/BASE PAIRED W/LT	0	$240.96	$0
270 AL COL BZ ON CUST BASE PAIRED W/LT	0	$143.28	$0
278 FG COL DIRECT BURY PAIRED W/LT	104	$132.12	$13,740
385 PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	0	$461.64	$0
386 80W LED POST TOP	0	$683.88	$0
396 WD POLE W/OH FEED-W/OR W/O LT	923	$95.04	$87,722
397 WD POLE W/UG FEED-PAIRED W/LT	109	$120.36	$13,119

AES Indiana
MU Lighting Rate Design

Streetlighting with CIAC - City of Indianapolis			
400 LED COBRA HEAD 5000-6000 LUMENS	13,346	$91.68	$1,223,506
401 LED COBRA HEAD 6500-7500 LUMENS	1,847	$95.64	$176,647
402 LED COBRA HEAD 12500-13500 LUMENS	6,422	$112.09	$719,836
403 LED COBRA HEAD 20000-21500 LUMENS	3,854	$131.51	$506,837
404 LED AREA LIGHT 11500-16500 LUMENS	3	$111.74	$335
405 LED AREA LIGHT 21000-26000 LUMENS	6	$135.06	$810
406 LED TRAD. POST TOP 6000-7500 LUMENS	0	$99.94	$0
407 LED TWIN WASH POST TOP 2 @ 6000-7500 L	0	$116.11	$0
408 LED WASH POST TOP 6000-7500 LUMENS	0	$96.40	$0
409 LED COBRA 12500-13500 L-OH FROM 215	12	$218.17	$2,618
410 LED COBRA 12500-13500L-METAL COL FRM 217	2	$344.65	$689
411 LED COBRA 6500-7500 L-OH FROM 218	12	$201.60	$2,419
412 LED COBRA 5000-6000 L-OH FROM 221	72	$197.76	$14,238
Streetlighting with CIAC - Non-City of Indianapolis			
400 LED COBRA HEAD 5000-6000 LUMENS	1,287	$106.68	$137,292
401 LED COBRA HEAD 6500-7500 LUMENS	273	$110.64	$30,205
402 LED COBRA HEAD 12500-13500 LUMENS	563	$127.09	$71,551
403 LED COBRA HEAD 20000-21500 LUMENS	121	$146.51	$17,728
404 LED AREA LIGHT 11500-16500 LUMENS	30	$126.74	$3,802
405 LED AREA LIGHT 21000-26000 LUMENS	0	$150.06	$0
406 LED TRAD. POST TOP 6000-7500 LUMENS	40	$114.94	$4,598
407 LED TWIN WASH POST TOP 2 @ 6000-7500 L	0	$131.11	$0
408 LED WASH POST TOP 6000-7500 LUMENS	162	$111.40	$18,046
409 LED COBRA 12500-13500 L-OH FROM 215	0	$233.17	$0
410 LED COBRA 12500-13500L-METAL COL FRM 217	0	$359.65	$0
411 LED COBRA 6500-7500 L-OH FROM 218	0	$216.60	$0
412 LED COBRA 5000-6000 L-OH FROM 221	0	$212.76	$0
Customer Installed, Owned, and Maintained (MU-1)			
55 250 WATT MV - CUSTOMER OWNED	2	$167.04	$334
56 175 WATT MV - CUSTOMER OWNED	26	$105.84	$2,752
59 400 WATT HPS - CUSTOMER OWNED	477	$168.60	$80,422
60 250 WATT HPS - CUSTOMER OWNED	270	$131.04	$35,381
61 150 WATT HPS - CUSTOMER OWNED	253	$97.80	$24,743
63 1000 WATT HPS - CUSTOMER OWNED	276	$354.84	$97,936
64 175 WATT MV ORNIMENTAL - CUSTOMER OWNED	2	$157.20	$314
109 400 WATT HPS-CUSTOMER OWNED WO/MAINT	56	$148.08	$8,292
111 150 WATT HPS - CUSTOMER OWNED WO/MAINT	0	$77.40	$0
112 1000 WATT HPS - CUSTOMER OWNED WO/MAINT	0	$298.32	$0
Customer Installed, Owned, but Company Maintained (MU-1)			
120 400 WATT HPS - CUSTOMER OWNED W/MAINT	13	$168.60	$2,192
Total MU-1	52,994		$8,770,863

AES Indiana
MU Lighting Rate Design

Code	Description	Inventory	Proposed Price Per Watt	Proposed Revenue
	Customer Installed, Owned, and Maintained (MU-4)			
	Total MU-4	1,312	$ 0.78	$604,465
	MU-4 Watts	774,956		
	Total MU	54,306		$9,375,329
			Target	$9,376,296
			Over (Under) Recovery	($968)

Code	Description	Minimum Wattage	Minimum Per Fixture or Device
	Customer Installed, Owned, and Maintained (MU-4)		
	MU-4 Rate Calculation	60	$ 46.80

AES Indiana 2023 Basic Rate Case
Cause No. 45911

Addendum to Settlement
Agreement

AES Indiana
Index of Financial Exhibits

Reference Identification	Description	Sponsoring Witness
AES Indiana-FS:		
FS1	Balance Sheets - Assets	Coklow
FS2	Balance Sheets - Capitalization and Liabilities	Coklow
FS3	Statements of Income	Coklow
FS4	Statement of Cash Flows	Coklow
AES Indiana-CC:		
CC1	Long-Term Debt	Illyes
CC2-S-R	Weighted Average Cost of Capital	Illyes
AES Indiana-REVREQ:		
REVREQ1-S-R	Allowable Electric Operating Income Requirement	Aliff
REVREQ2-S-R	Gross Revenue Conversion Factor	Miller
AES Indiana-RB:		
RB1-S-R	Original Cost Electric Rate Base Per Books at December 31, 2022 and Pro Forma	Coklow
RB2	Total Per Books Utility Plant in Service at Original Cost	Nyhuis
RB3-S-R	Addition of ACE Project	Aliff/Barbarisi
RB4	Removal of Eagle Valley Outage Capital and Pete 2 Retirements	Aliff
RB5	Per Books Non-jurisdictional MISO MTEP Plant in Service	Aliff
RB6	Per Books Asset Retirement Cost	Nyhuis
RB7-S-R	Electric Materials and Supplies Inventory	Bigalbal/Coklow/Holtsclaw
RB8	Electric Fuel Stock Inventory	Dickerson
RB9-S-R	Regulatory Assets Includable as Electric Rate Base	Aliff/Nyhuis
AES Indiana-OPER:		
OPINC-S-R	Statements of Electric Operating Income, Per Books and Jurisdictional Pro Forma at Present and Proposed Rates	Coklow
REV1-S-R	Summary of Electric Operating Revenue, Per Books and Pro Forma at Present and Proposed Rates	Coklow
REV2-R	Summary of Electric Operating Revenue Adjustments	Coklow
REV3	Summary Taking Total Retail Revenue to Retail Basic Rates Revenue	Baker
REV4	Summary of Retail Basic Rates Revenue Adjustments for Weatherization, Customer Annualization, DSM Installations Annualization and to Remove Unbilled Revenues	Baker
REV5-S-R	Summary of Electric Operating Revenue Adjustments Adding Back Pro Forma at Present Rates Rider Revenues to Achieve Total Retail Revenue Pro Forma at Present Rates	Aliff
REV6	Summary of Off-System Sales	Steiner
REV7	Summary of Electric Rent Revenue	Coklow
REV8	Summary of Miscellaneous Electric Revenue	Aliff
REV9	Pro Forma Adjustment to Capacity Sales	Steiner
REV10-S-R	Electric Operating Revenue Adjustment Taking Pro Forma at Present Rates to Pro Forma at Proposed Rates	Baker/Rimal

AES Indiana
Index of Financial Exhibits

Reference Identification	Description	Sponsoring Witness
OM1-S-R	Summary of Pro Forma Adjustments to Electric Operation and Maintenance Expense	Coklow
OM2-S-R	Cost of Fuel and Purchased Power	Dickerson
OM3	Capacity Costs	Steiner
OM4	Off-System Sales Power Production Costs	Steiner
OM5-S-R	Generation Consumables Variable Expense	Steiner
OM6	Remove Certain Transportation Expenses	Coklow
OM7	Non-Outage Operating and Maintenance Costs	Bigalbal
OM8	Seasonal NOx Emission Allowance Expense	Steiner
OM9	Obsolete/Damaged Materials and Supplies Inventory Write-Offs Expense	Coklow
OM10	Non-Jurisdictional MISO MTEP Operating and Maintenance Expenses	Aliff
OM11	Storm Expenses	Aliff/Holtsclaw
OM12-S-R	Vegetation Management Costs	Bocook
OM13	MISO Non-Fuel Costs	Aliff
OM14	MISO Deferred Expense Amortization	Aliff
OM15-S-R	Wages of AES Indiana and AES U.S. Services, LLC Employees	Whitehead
OM16	Employee Insurance for AES Indiana and AES U.S. Services, LLC	Whitehead
OM17	Pension Expense and OPEB	Roach
OM18-S-R	ACE Project O&M Expense	Barbarisi
OM19	Image-Building Advertising Costs	Robinson
OM20	Injuries and Damages Expense	Robinson
OM21-S-R	Amortization of Rate Case Expense	Robinson
OM22-S-R	Miscellaneous Expense Adjustments	Coklow
OM23	AES U.S. Services, LLC Occupancy and Non-Labor Costs	Nyhuis
OM24	Remove ECR, TDSIC Tracker Items not Removed Elsewhere	Aliff
OM25	Property and Casualty Insurance Expense	Robinson
OM26	Write-Off of Preliminary Survey and Investigation Charges and Cancelled Capital Projects	Coklow
OM27-S-R	Uncollectible Accounts Expense	Robinson
OM28-S-R	Public Utility Fee	Robinson
DEPR-S-R	Depreciation and Amortization Expense	Nyhuis
OTX1-S-R	Summary of Taxes Other Than Income Taxes	Miller
OTX2	Real Estate and Personal Property Taxes, Including Rail Car Tax	Miller
OTX3-S-R	Payroll Taxes	Whitehead
OTX4	Indiana Utility Receipts Tax	Miller
TX1-S-R	Summary of Income Taxes	Miller
TX2-S-R	Current Federal Income Tax Expense	Miller
TX3-S-R	Current State Income Tax Expense	Miller
TX4-S-R	Federal and State Deferred Income Tax Expense	Miller
TX5	Investment Tax Credit Expense	Miller
TX6-S-R	Interest Expense for Interest Synchronization	Miller
TX7	Imputation of Parent Company Interest	Miller
TX8-S-R	Calculation of Effective Income Tax Rate	Miller

AES Indiana
Balance Sheets as of December 31, 2022 and December 31, 2021
(Thousands of Dollars)

ASSET
S

Line No.		At 12/31/2022	At 12/31/2021	Line No.
	UTILITY PLANT:			
1	Utility Plant in Service	$ 7,077,649	$ 6,765,414	1
2	Less: Accumulated Depreciation	4,057,940	3,844,418	2
3	Net Utility Plant in Service	3,019,708	2,920,996	3
4	Construction Work in Progress	280,732	236,696	4
5	Other Utility Plant - Net	1,002	1,002	5
6	Total Utility Plant	$ 3,301,443	$ 3,158,694	6
	OTHER PROPERTY AND INVESTMENTS:			
7	Other Property and Investments	$ 6,164	$ 4,824	7
	CURRENT ASSETS:			
8	Cash and Cash Equivalents	$ 199,094	$ 2,756	8
9	Accounts Receivable (Less Allowance for Doubtful Accounts of $1,117 and $647, respectively)	155,871	132,737	9
10	Fuel Stock	60,146	41,567	10
11	Plant Materials and Operating Supplies	116,158	86,981	11
12	Prepayments and Other Current Assets	115,813	102,347	12
13	Total Current Assets	$ 647,081	$ 366,388	13
	DEFERRED DEBITS:			
14	Unamortized Debt Expenses	$ 21,498	$ 18,229	14
15	Rate-Based Regulatory Assets	414,885	411,613	15
16	Non Rate-Based Regulatory Assets	586,190	446,614	16
17	Unamortized Loss on Reacquired Debt	14,429	15,703	17
18	Accumulated Deferred Income Taxes - FAS 109	(4,566)	(4,556)	18
19	Accumulated Deferred Income Taxes - Other	181,950	218,255	19
20	Miscellaneous	37,839	57,012	20
21	Total Deferred Debits	$ 1,252,227	$ 1,162,869	21
22	TOTAL ASSETS	$ 5,206,916	$ 4,692,775	22

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule FS2

AES Indiana
Balance Sheets as of December 31 , 2022 and December 31, 2021
(Thousands of Dollars)

CAPITALIZATION AND LIABILITIES

Line No.		At December 31, 2022	At December 31, 2021	Line No.
	PROPRIETARY CAPITAL:			
1	Common Stock Issued	$ 324,537	$ 324,537	1
2	Preferred Stock Issued	—	59,135	2
3	Premium on Cumulative Preferred Stock	—	649	3
4	Other Paid In Capital	1,193,107	939,994	4
5	Retained Earnings	419,818	422,490	5
6	Unappropriated Undistributed Subsidiary Earnings/(Deficit)	5,648	4,307	6
7	Total Proprietary Capital	$ 1,943,109	$ 1,751,111	7
	LONG-TERM DEBT:			
8	Bonds	$ 2,153,800	$ 1,803,800	8
9	Unamortized Discount on Long-Term Debt	(6,651)	(5,855)	9
10	Total Long-Term Debt	$ 2,147,149	$ 1,797,945	10
	OTHER NONCURRENT LIABILITIES:			
11	Obligations Under Capital Leases-Noncurrent	$ —	$ —	11
12	Accumulated Provision for Injuries and Damages	—	200	12
13	Accumulated Provision for Pensions and Benefits	278	239	13
14	Accumulated Miscellaneous Operating Provisions	—	1,000	14
15	Long-Term Portion of Derivative Instrument Liabilities	—	—	15
16	Asset Retirement Obligations	217,570	189,509	16
17	Total Other Noncurrent Liabilities	$ 217,847	$ 190,948	17
	CURRENT AND ACCRUED LIABILITIES:			
18	Accounts Payable	$ 184,064	$ 159,191	18
19	Short Term Debt	—	60,000	19
20	Customer Deposits	35,097	28,917	20
21	Taxes Accrued	14,124	16,341	21
22	Interest Accrued	24,526	22,241	22
23	Dividends Declared	7,500	7,500	23
24	Tax Collections Payable	8,353	6,908	24
25	Other Current Liabilities	24,314	26,653	25
26	Total Current & Accrued Liabilities	$ 297,978	$ 327,750	26
	DEFERRED CREDITS:			
27	Accumulated Deferred Investment Tax Credits	$ 24	$ 27	27
28	Other Deferred Credits	3,127	4,339	28
29	Other Regulatory Liabilities	117,137	108,177	29
30	Accumulated Deferred Income Taxes - FAS 109	(93,227)	(104,728)	30
31	Accumulated Deferred Income Taxes - Other	573,772	617,205	31
32	Total Deferred Credits	$ 600,833	$ 625,020	32
33	TOTAL CAPITALIZATION AND LIABILITIES	$ 5,206,916	$ 4,692,775	33

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule FS3

AES Indiana
Statements of Income
For the Twelve Month Periods Ended December 31, 2022 and December 31, 2021
(Thousands of Dollars)

Line No.		Twelve Months Ended December 31, 2022		Twelve Months Ended December 31, 2021	Line No.
1	OPERATING REVENUES	$ 1,787,190		$ 1,426,197	1
	OPERATING EXPENSES:				
2	Operating Expense	$ 1,064,676		$ 700,694	2
3	Maintenance Expense	177,654		160,266	3
4	Depreciation Expense	295,119		282,032	4
5	Amortization of Depletion of Plant	16,253		11,477	5
6	Amortization of Utility Plant Acquisition Adjustment	22		13	6
7	Amortization of Regulatory Debits/Credits	(39,302)		(37,205)	7
8	Taxes Other Than Income Taxes	33,464		45,214	8
9	Income Taxes - Federal	31,385		36,412	9
10	Income Taxes - Other	8,168		10,265	10
11	Net Deferred Income Taxes - Federal	(7,278)		(8,410)	11
12	Net Deferred Income Taxes - Other	125		(366)	12
13	ITC Adjustment, Net	(3)		2	13
14	Gains on Disposition of Allowances	(4,358)	(1)	—	14
15	ARO Accretion and Loss on ARO Settlements	—		—	15
16	Total Utility Operating Expenses	$ 1,575,927		$ 1,200,395	16
17	Net Utility Operating Income	$ 211,263		$ 225,802	17
	NONUTILITY OPERATING INCOME:				
18	Revenues from Nonutility Operations	$ 10		$ 15	18
19	Expenses of Nonutility Operations	(13)		(9)	19
20	Non-operating Rental Income	99		1,020	20
21	Equity in Earnings of Subsidiaries	1,416		4,284	21
22	Interest and Dividend Income	672		19	22
23	Allowance for Equity Funds Used During Construction	4,784		5,417	23
24	Miscellaneous Non-operating Income	6		4	24
25	Gain on Disposition of Property	—		—	25
26	Total Other Income	$ 6,974		$ 10,750	26
	OTHER INCOME DEDUCTIONS:				
27	Loss on Disposition of Property	$ —		$ —	27
28	Miscellaneous Amortization	—		—	28
29	Donations	1,234		1,479	29
30	Penalties	100		4	30
31	Civic Expenditures	588		552	31
32	Other Deductions	200		215	32
33	Taxes on Other Income and Deductions	54		0	33
34	Total Other Income Deductions	$ 2,176		$ 2,251	34
	INTEREST CHARGES:				
35	Interest on Long-Term Debt	$ 87,166		$ 83,866	35
36	Amortization of Debt Discount	1,260		1,221	36
37	Amortization of Loss on Reacquired Debt	6,471		3,785	37
38	Other Interest Expense	—		—	38
39	Allowance for Borrowed Funds Used During Construction	(8,215)		(4,815)	39
40	Net Interest Charges	$ 86,682		$ 84,058	40
41	NET INCOME	$ 129,378		$ 150,243	41

(1) These dollars have been reclassified against Operating Revenues (specifically Misc Revenues on REV8) in determining beginning balances for OPINC and REV1.

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule FS4

AES Indiana
Statement of Cash Flows
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.			Twelve Months Ended December 31, 2022	Line No.
	NET CASH FLOW FROM OPERATING ACTIVITIES:			
1	Net income	$	129,378	1
	NONCASH CHARGES (CREDITS) TO INCOME:			
2	Depreciation and Depletion	$	263,791	2
3	Amortization of of Debt Discounts, Premiums, & Expenses		2,511	3
4	Deferred Income Taxes (Net)		(7,152)	4
5	Investment Tax Credit Adjustment (Net)		(3)	5
6	Net (Increase) Decrease in Receivables		(38,699)	6
7	Net (Increase) Decrease in Inventory		(47,894)	7
8	Net (Increase) Decrease in Allowances Inventory		—	8
9	Net Increase (Decrease) in Payables and Accrued Expenses		38,617	9
10	Net (Increase) Decrease in Other Regulatory Assets		20,295	10
11	Net Increase (Decrease) in Other Regulatory Liabilities		16,663	11
12	(Less) Allowance for Other Funds Used During Construction		4,784	12
13	(Less) Undistributed Earnings from Subsidiary Companies		1,313	13
14	Net (Decrease) Increase in Pension & OPEB benefits		(8,727)	14
15	Accrued taxes payable/receivable		(29)	15
16	Other miscellaneous		13,065	16
17	Net cash provided by operating activities	$	375,719	17
	CASH FLOWS FROM INVESTMENT ACTIVITIES:			
18	Gross Additions to Utility Plant	$	(393,167)	18
19	(Less) Allowance for Other Funds Used During Construction		(3,261)	19
20	Asset Removal Costs Net of Salvage		(23,948)	20
21	Net change in construction payables		(14,200)	21
22	Cash outflows for plant	$	(428,054)	22
23	Acquisition of Other Noncurrent Assets		(3,910)	23
24	Investments in and Advances to Assoc. and Subsidiary Companies		(94,862)	24
25	Other		(719)	25
26	Net cash used in investing activities	$	(527,546)	26
	CASH FLOWS FROM FINANCING ACTIVITIES:			
27	Long-Term Debt	$	350,000	27
28	Issuance of Short-Term Debt		—	28
29	Equity Contribution from Parent		253,000	29
30	Net Increase in Short-Term Debt		500,000	30
31	Cash Provided by Outside Sources	$	1,103,000	31
	PAYMENTS FOR RETIREMENT OF:			
32	Long-term Debt	$	—	32
33	Preferred Stock		(60,080)	33
34	Other		(33)	34
35	Net Decrease in Short-Term Debt		(560,000)	35
36	Debt Issuance Costs		(4,309)	36
37	Dividends on Preferred Stock		(3,213)	37
38	Dividends on Common Stock		(127,200)	38
39	Net cash provided by financing activities	$	348,165	39
40	NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	$	196,338	40
41	Cash and cash equivalents at beginning of period		2,756	41
42	Cash and cash equivalents at end of period	$	199,094	42

AES Indiana
Long-Term Debt as of December 31, 2022
(Thousands of Dollars)

Line No.	Series	Maturity Date	Principal Outstanding at December 31, 2022	Pro Forma Adjustments	Total Pro Forma	Effective Interest Rate (1)	Annual Cost	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
	Secured 1st Mortgage Bonds							
1	5.65% series, due December, 2032	12/1/2032	$ 350,000	$ —	$ 350,000	5.82 %	$ 20,363	1
2	1.40% series, due August, 2029	8/1/2029	55,000	—	55,000	1.59 %	877	2
3	.65% series, due August, 2025	8/1/2025	40,000	—	40,000	1.04 %	417	3
4	3.125% series, due December, 2024	12/1/2024	40,000	—	40,000	3.81 %	1,522	4
5	6.60% series, due January, 2034	1/1/2034	100,000	—	100,000	6.82 %	6,816	5
6	6.05% series, due October, 2036	10/1/2036	158,800	—	158,800	6.23 %	9,894	6
7	6.60% series, due June, 2037	6/1/2037	165,000	—	165,000	6.68 %	11,021	7
8	4.875% series, due November, 2041	11/1/2041	140,000	—	140,000	5.74 %	8,042	8
9	4.65% series, due June, 2043	6/1/2043	170,000	—	170,000	4.73 %	8,047	9
10	4.50% series, due June, 2044	6/1/2044	130,000	—	130,000	4.66 %	6,055	10
11	4.70% series, due September, 2045	9/1/2045	260,000	—	260,000	4.81 %	12,498	11
12	4.05% series, due May, 2046	5/1/2046	350,000	—	350,000	4.15 %	14,541	12
13	4.875% series, due November, 2048	11/1/2048	105,000	—	105,000	3.94 %	4,134	13
14	.75% series, due April, 2026	4/1/2026	30,000	—	30,000	0.97 %	292	14
15	.95% series, due April, 2026	4/1/2026	60,000	—	60,000	1.17 %	705	15
16	Total before premium		$ 2,153,800	$ —	$ 2,153,800		$ 105,225	16
17	Unamortized redemption premium		$ (764)	$ —	$ (764)		$ 262	17
18	Totals		$ 2,153,036	$ —	$ 2,153,036		$ 105,487	18
19	Weighted Effective Interest Rate (Col. 6 / Col. 4)					4.90 %		19

(1) Calculated as required by Accounting Standard Update (ASU) No. 835-30-35 and ASU No. 835-30-20.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper CC1.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule CC1

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule CC2-S-R

AES Indiana
Weighted Average Cost of Capital
(Thousands of Dollars)

Line No.	Component of Capitalization	Balance at December 31, 2022 (Col. 1)		Percent of Total (Col. 2)	Return Rate (Col. 3)		Weighted Return Rate (Col. 4)	Line No.
1	Long-Term Debt	$ 2,153,036		49.15 %	4.90 %		2.41 %	1
2	Preferred Stock	—		— %	— %		— %	2
3	Common Equity	1,943,109		44.36 %	9.90 %	(2)	4.39 %	3
4	Customer Deposits	35,097		0.80 %	6.00 %		0.05 %	4
5	Prepaid Pension Asset (net of OPEB liability)	(133,100)	(1)	(3.04)%	— %		— %	5
6	Deferred Income Taxes	382,560		8.73 %	— %		— %	6
7	Post 1970 ITC	24		— %	7.28 %	(3)	— %	7
8	Totals	$ 4,380,726		100.00 %			6.85 %	8

(1) Please see AES Indiana Attachment HMR-2

(2) Provided by AES Indiana Witness McKenzie

(3) Computed as the weighted return on investor-supplied capital:

Long-Term Debt	$ 2,153,036	52.56 %	4.90 %	2.58 %
Preferred Stock	—	— %	— %	— %
Common Equity	1,943,109	47.44 %	9.90 %	4.70 %
	$ 4,096,145	100.00 %		7.28 %

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper CC2.

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule REVREQ1-S-R

AES Indiana
Allowable Electric Operating Income Requirement
(Thousands of Dollars)

Line No.		(Col. 1)	Supporting AES Indiana Financial Exhibit Reference (Col. 2)	Line No.
1	Original cost rate base	$ 3,444,878	AESI-RB, Schedule RB1-S-R Column 6, Line 9	1
2	Rate of return	6.85 %	AESI-CC, Schedule CC2-S-R	2
3	Allowable electric operating income	235,972	Line 1 multiplied by Line 2	3
4	Less: Electric operating income pro forma at present rates	$ 182,885	AESI-OPER, Schedule OPINC-S-R, Column 4, Line 13	4
5	Deficiency in electric operating income	53,087		5
6	Revenue conversion factor	0.747322	AESI-REVREQ, Schedule REVREQ2-S-R, Line 19	6
7	Deficiency in electric operating revenue	$ 71,037	Line 5 divided by Line 6	7
8	Additional operating revenue produced by proposed rates	$ 71,037	AESI-OPER, Schedule OPINC-S-R, Column 5, Line 1	8

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule REVREQ2-S-R

AES Indiana
Gross Revenue Conversion Factor
At December 31, 2022

Line No.			(Col. 1)	Supporting AESI Financial Exhibit Reference (Col. 2)	Line No.
1	Revenue		1.000000		1
2	Less:	Uncollectibles	0.003814	AESI-OPER, Schedule OM27-S-R	2
3		Public utility fee	0.001468	AESI-OPER, Schedule OM28-S-R	3
4	State tax base		0.994718		4
5	Times: State tax rate		0.049000	AESI-OPER, Schedule TX3-S-R	5
6	Effective state tax rate		0.048741		6
7	Revenue		1.000000		7
8	Less:	Uncollectibles	0.003814	AESI-OPER, Schedule OM27-S-R	8
9		Public utility fee	0.001468	AESI-OPER, Schedule OM28-S-R	9
10		Effective state tax rate	0.048741	Line 6, above	10
11	Federal tax base		0.945977	Line 7, less Lines 8-10	11
12	Times: Federal tax rate		0.210000	AESI-OPER, Schedule TX2-S-R	12
13	Effective federal tax rate for taxable income		0.198655		13
14	Revenue		1.000000		14
15	Less:	Uncollectibles	0.003814	AESI-OPER, Schedule OM27-S-R	15
16		Public utility fee	0.001468	AESI-OPER, Schedule OM28-S-R	16
17		Effective state tax rate	0.048741	Line 6, above	17
18		Effective federal tax rate for income	0.198655	Line 13, above	18
19	Revenue conversion factor		0.747322		19

AES Indiana
Original Cost Electric Rate Base
Per Books at December 31, 2022 and Pro Forma
(Thousands of Dollars)

Line No.	Description	Plant in Service (Col. 1)	Accumulated Depreciation And Amortization (Col. 2)	Materials and Supplies Inventory (Col. 3)	Fuel Stock Inventory (Col. 4)	Regulatory Assets (Col. 5)	Totals (Col. 6)	Line No.
1	Per books (Schedules RB2, RB7, RB8, RB9)	$ 7,077,649	$ (4,057,940)	$ 115,958	$ 55,780	$ 411,614	$ 3,603,060	1
2	Add ACE Project (Schedule RB3)	83,838	—	—	—	—	83,838	2
3	Remove Eagle Valley Outage Capital Costs and Pete 2 and Pete 1 & 2 Shared Assets (Schedule RB4)	(512,743)	492,909	—	—	—	(19,834)	3
4	Remove non-jurisdictional MISO MTEP plant in service (Schedule RB5)	(20,788)	3,447	—	—	—	(17,341)	4
5	Remove net asset retirement cost (Schedule RB6)	(196,676)	154,349	—	—	—	(42,326)	5
6	Adjustment to materials & supplies inventory (Schedule RB7)	—	—	(4,923)	—	—	(4,923)	6
7	Adjustment to fuel stock inventory (Schedule RB8)	—	—	—	(26,728)	—	(26,728)	7
8	Adjustment to regulatory assets (Schedule RB9)	—	—	—	—	(130,869)	(130,869)	8
9	Pro forma original cost rate base	$ 6,431,281	$ (3,407,235)	$ 111,035	$ 29,052	$ 280,745	$ 3,444,878	9

AES Indiana 2023 Basic Rate Case
AES Indiana Attachment CAR-2S
Schedule RB2

AES Indiana

Total Per Books Utility Plant In Service at Original Cost

(Thousands of Dollars)

Line No.	Description	Total Per Books Plant In Service at December 31, 2022 Original Cost (Col. 1)	Line No.
1	Intangible plant	$ 46	1
2	Systems software	153,606	2
3	Production plant	4,165,600	3
4	Transmission plant	461,042	4
5	Distribution plant	2,036,697	5
6	General plant	260,172	6
7	Total utility plant in service	7,077,164	7
8	Production plant acquisition adjustment	485	8
9	Total utility plant including acquisition adjustment (See Schedule RB1, Line 1, Col. 1)	7,077,649	9
10	Accumulated utility plant in service depreciation	(4,057,713)	10
11	Accumulated amortization of production plant acquisition adjustment	(227)	11
12	Total accumulated depreciation and amortization (See Schedule RB1, Line 1, Col. 2)	(4,057,940)	12
13	Net utility plant in service (Line 9, less Line 12)	$ 3,019,708	13

AES Indiana
Pro Forma Adjustment to Include Addition of ACE Project
(Thousands of Dollars)

Line No.	Description	Total Projected Project Costs (Col. 1)	Total Per Books In Service at Dec 31, 2022 (Col. 2)	Pro Forma Adjustment (Col. 3)	Line No.
1	Miscellaneous Intangible Plant (Software System)	$ 79,934	$ —	$ 79,934	1
2	AFUDC	3,904	—	3,904	2
3	Net projected and per book totals	$ 83,838	$ —	$ 83,838	3
4	Net pro forma addition to plant in service (See Schedule RB1, Line 2, Column 1)			$ 83,838	4

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB3.

AES Indiana
Pro Forma Adjustment to Remove Petersburg Unit 2 and Unit 1 & 2 Shared Assets and Eagle Valley Forced Outage Capital Costs
(Thousands of Dollars)

Line No.	Description	Pete Unit 2 and 1&2 Shared Assets Retirements (1)	Eagle Valley Forced Outage (2)	All Projects	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
	Gross Utility Plant:				
	Construction Costs:				
1	Intangible plant	$ —	$ —	$ —	1
2	Systems software	—	—	—	2
3	Production plant	501,630	11,112	512,743	3
4	Transmission plant	—	—	—	4
5	Distribution plant	—	—	—	5
6	General plant	—	—	—	6
7	Total Utility Plant	501,630	11,112	512,743	7
8	Pro-Forma In-Service Plant at December 31, 2022	—	—	—	8
9	Pro-Forma Adjustment to Total Utility Plant (See Schedule RB1 Line 3 Column 1)	$ (501,630)	$ (11,112)	$ (512,743)	9
		Pete Unit 2 and 1&2 Shared Assets Retirements	Eagle Valley Forced Outage	All Projects	
	Accumulated Depreciation:				
10	Per Books December 31, 2022	$ (492,819)	$ (90)	$ (492,909)	10
11	Pro-Forma Accumulated Depreciation at December 31, 2022	—	—	—	11
12	Pro Forma Adjustment (See Schedule RB1, Line 3, Column 2)	$ 492,819	$ 90	$ 492,909	12
13	Net Difference	$ (8,812)	$ (11,022)	$ (19,834)	13

(1) Removal of PETE Unit 2 and Shared Assets for Pete 1&2, which is included in utility plant in service on Schedule RB2.
(2) Removal of Eagle Forced Outage per FAC 133 S1 Order, which is included in utility plant in service on Schedule RB2.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Schedule RB4-WP1.

AES Indiana
Pro Forma Adjustment to Remove
Per Books Non-Jurisdictional MISO MTEP (1) Plant In Service
(Thousands of Dollars)

Line No.	Description	Total Per Books Non-Jurisdictional Plant In Service at December 31, 2022 Original Cost (Col. 1)	Line No.
1	Intangible plant	$ —	1
2	Systems software	—	2
3	Production plant	—	3
4	Transmission plant	(20,788)	4
5	Distribution plant	—	5
6	General plant	—	6
7	Total (See Schedule RB1, Line 4, Col. 1)	(20,788)	7
8	Less: Accumulated depreciation (See Schedule RB1, Line 4, Col. 2)	3,447	8
9	Net non-jurisdictional MISO MTEP plant in service	$ (17,341)	9

(1) MISO Transmission Expansion Plan ("MTEP")

AES Indiana
Pro Forma Adjustment to Remove Per Books Asset Retirement Cost
(Thousands of Dollars)

Line No.	Description	Total Per Books Asset Retirement Cost at December 31, 2022 Original Cost (Col. 1)	Line No.
1	Intangible plant	$ —	1
2	Systems software	—	2
3	Production plant	(195,718)	3
4	Transmission plant	(30)	4
5	Distribution plant	(235)	5
6	General plant	(693)	6
7	Total (See Schedule RB1, Line 5, Column 1)	(196,676)	7
8	Less: Accumulated depreciation (See Schedule RB1, Line 5, Column 2)	154,349	8
9	Net asset retirement cost	$ (42,326)	9

AES Indiana
Electric Materials and Supplies Inventory
Per Books at December 31, 2022 and Pro Forma
(Thousands of Dollars)

Line No.		T&D Non-Capital Spare 5 Mo. Average	Other Materials & Supplies 13 Mo. Average	Total Average	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	December 31, 2021	$ —	$ 60,653		1
2	January 31, 2022	—	60,990		2
3	February 28, 2022	—	61,421		3
4	March 31, 2022	—	61,590		4
5	April 30, 2022	—	61,697		5
6	May 31, 2022	—	61,035		6
7	June 30, 2022	—	60,159		7
8	July 31, 2022	—	60,794		8
9	August 31, 2022	43,555	61,239		9
10	September 30, 2022	49,360	61,598		10
11	October 31, 2022	50,616	61,719		11
12	November 30, 2022	51,610	61,904		12
13	December 31, 2022	53,335	62,623		13
14	Average	$ 49,695	$ 61,340	$ 111,035	14
15	Less: Per books at December 31, 2022			115,958	15
16	Pro forma adjustment (Line 14, less Line 15) (See Schedule RB1, Line 6, Column 3)			$ (4,923)	16

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule RB7-S-R

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB7.

AES Indiana
Electric Fuel Stock Inventory
Per Books at December 31, 2022 and Pro Forma

Line No.		(Col. 1)	(Col. 2)	(Col. 3)	Line No.
	Fuel Stock (151)				
	Coal	Tons	Cost per Ton	Total Cost (in 000's)	
	Per Books Inventory at December 31, 2022:				
1	Petersburg	1,065,105	$ 49	$ 52,512	1
2	Harding Street	0	—	—	2
3	Eagle Valley	0	—	—	3
4	Total actual coal inventory	1,065,105	$ 49	$ 52,512	4
	Oil	Gallons	Cost		
5	Petersburg	413,597	$ 4	$ 1,711	5
6	Harding Street	853,429	2	1,557	6
7	Total actual oil inventory	1,267,026	$ 3	$ 3,268	7
8	Total per books inventory			$ 55,780	8
	Pro Forma Inventory Level:	Tons	Cost per Ton	Total Cost (in 000's)	
9	Petersburg	525,000	$ 49	$ 25,883	9
10	Harding Street	0	—	—	10
11	Eagle Valley	0	—	—	11
12	Total pro forma coal inventory	525,000	$ 49	$ 25,883	12
	Oil	Gallons	Cost		
13	Petersburg	325,000	$ 4	$ 1,344	13
14	Harding Street	1,000,000	2	1,824	14
15	Total pro forma oil inventory	1,325,000	$ 2	$ 3,169	15
16	Total pro forma inventory			$ 29,052	16
17	Pro forma adjustment (Line 16, less Line 8) (See Schedule RB1, Line 7, Column 4)			$ (26,728)	17

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB8.

AES Indiana
Regulatory Assets Includable as Electric Rate Base
(Thousands of Dollars)

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
1	Unamortized Petersburg Unit No. 4 deferred costs and carrying charges: Unit 4 depreciation and post-in-service AFUDC deferred from the April 28, 1986 in-service date through the August 6, 1986 IURC order in Cause No. 37837	$ 2,478			$ 2,478	$ 676		1
2	Unamortized post in-service AFUDC from the August 6, 1986 IURC order in Cause No. 37837 through the August 24, 1995 IURC order in Cause No. 39938	1,388			1,388	379		2
3	Total Petersburg Unit No. 4 deferred costs	3,866			3,866	1,055	(1)	3
4	Unamortized post in-service AFUDC on projects approved in the November 14, 2002 IURC order in Cause No. 42170, the November 30, 2004 IURC order in Cause No. 42700, the April 2, 2008 IURC order in Cause No. 43403, the August 14, 2013 IURC order in Cause No. 44242, and the July 29, 2015 IURC order in Cause No. 44540	10,833			10,833	988	(2)	4
5	Unamortized deferred depreciation on projects approved in the April 2, 2008 IURC order in Cause No. 43403, the August 14, 2013 IURC order in Cause No. 44242, and the July 29, 2015 IURC order in Cause No. 44540	14,012			14,012	1,401	(3)	5
6	Depreciation of NAAQS-DBA deferred per the April 26, 2017 order in Cause No. 44794	36			36	4	(4)	6
7	Unamortized post in-service AFUDC for NAAQS-DBA per the April 26, 2017 order in Cause No. 44794	71			71	7	(5)	7
8	Depreciation of CCR Bottom Ash deferred per the April 26, 2017 order in Cause No. 44794	847			847	85	(6)	8
9	Unamortized post in-service AFUDC for CCR Bottom Ash per the April 26, 2017 order in Cause No. 44794	353			353	35	(7)	9

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
10	Depreciation of NAAQS-Other projects deferred per the April 26, 2017 order in Cause No. 44794	$ 471			$ 471	$ 47	(8)	10
11	Unamortized post in-service AFUDC for NAAQS-Other projects per the April 26, 2017 order in Cause No. 44794	359			359	36	(9)	11
12	Depreciation of Eagle Valley CCGT and Harding Street 5 & 6 Refueling deferred per the May 14, 2014 IURC order in Cause No. 44339	16,335			16,335	838	(10)	12
13	Unamortized post in-service AFUDC for the Eagle Valley CCGT and Harding Street 5 & 6 refueling per the May 14, 2014 IURC order in Cause No. 44339	33,110			33,110	1,643	(11)	13
14	Electric vehicle regulatory asset deferred per the March 18, 2015 IURC order in Cause No. 44478	625			625	106	(12)	14
15	Harding Street Unit 7 Preservation Costs deferred per the June 22, 2016 IURC order in Cause No. 42170 - ECR 26	1,482			1,482	423	(13)	15
16	20% HS7 Gas Conversion revenue requirement deferred per the July 29, 2015 IURC order in Cause No. 44540	(2,151)			(2,151)	(538)	(14)	16

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
17	20% NPDES revenue requirement deferred per the July 29, 2015 IURC order in Cause No. 44540	$ 14,439			$ 14,439	$ 3,610	(14)	17
18	20% NAAQS DBA revenue requirement deferred per the April 26, 2017 IURC order in Cause No. 44794	719			719	180	(15)	18
19	20% CCR Bottom Ash revenue requirement deferred per the April 26, 2017 IURC order in Cause No. 44794	1,593			1,593	398	(15)	19
20	20% NAAQS Other revenue requirement deferred per the April 26, 2017 IURC order in Cause No. 44794	2,198			2,198	549	(15)	20
21	Unamortized Petersburg Unit 1 capital costs at retirement date deferred per the November 17, 2021 IURC order in Cause No. 45502	47,543	(6,667)		40,876	5,000	(16)	21
22	Unamortized Petersburg 2 (& Pete 1&2 Shared) capital costs at retirement date deferred per the November 17, 2021 IURC order in Cause No. 45502	239,920	(124,202)		115,718	11,572	(16.1)	22
23	Depreciation of TDSIC deferred per the March 4, 2020 IURC order in Cause No. 45264, original filing	6,737			6,737	189	(17)	23
24	Unamortized post in-service AFUDC for TDSIC per the March 4, 2020 IURC order in Cause No. 45264, original filing	11,133			11,133	309	(18)	24
25	20% TDSIC Distribution revenue requirement deferred per the March 4, 2020 IURC order in Cause No. 45264, TDSIC 1	6,073			6,073	1,518	(19)	25

Line No.	Description	Regulatory Asset Balance at 12/31/2022 (Col. 1)	Projected Activity Through 5/31/2023 (Col. 2)	Less: Temporary Rates Credit (Col. 3)	Pro Forma Adjusted Balances (Col. 4)	Annual Amortization to Electric Cost of Service (Col. 5)		Line No.
26	20% TDSIC Transmission revenue requirement deferred per the March 4, 2020 IURC order in Cause No. 45264, TDSIC 1	$ 1,010			$ 1,010	$ 252	(19)	26
27	Total of rate base regulatory assets, agrees to RB9-WP1	$ 411,614	$ (130,869)	$ —	$ 280,745	$ 29,707		27
28	Net pro forma regulatory assets adjustment (See Schedule RB1, Line 8)			$ (130,869)				28
29	Eagle Valley forced outage- FAC 133S1 Settlement & Order, not included in rate base and amortized over 25 years (see Schedule RB4)	11,022			11,022	441	(20)	29
30	Foregone revenues deferred related to COVID-19 per the June 29, 2020 IURC order in Cause No. 45380-Phase 1	5,426	—	—	5,426	1,357	(21)	30
31	Total regulatory assets not included in rate base	$ 16,448	$ —	$ —	$ 16,448			31
32	Total pro forma amortization expense (Included in Schedule DEPR)					$ 31,505	(22)	32

(1) The pro forma annual amortization was calculated by dividing the original cost of $32,688,591 by the useful life of 31 years at August 31, 1995.

(2) The pro forma annual amortization was calculated by dividing the original post in service AFUDC on Petersburg assets by the useful by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets. HS7 carrying costs are amortized at the same level as approved in the prior rate case.

(3) The pro forma annual amortization was calculated by dividing the original deferred depreciation by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.

(4) The pro forma annual amortization was calculated by dividing the deferred depreciation for the NAAQS-DBA projects by a 10 year amortization based on the depreciation study and consistent with Petersburg Unit 2 assets.

(5) The pro forma annual amortization was calculated by dividing the deferred carrying charges for the NAAQS-DBA projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.

(6) The pro forma annual amortization was calculated by dividing the deferred depreciation for the CCR Bottom Ash projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.

(7) The pro forma annual amortization was calculated by dividing the deferred carrying charges for the CCR Bottom Ash projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.

(8) The pro forma annual amortization was calculated by dividing the deferred depreciation for the NAAQS-Other projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.

(9) The pro forma annual amortization was calculated by dividing the deferred carrying charges for the NAAQS-Other projects by a 10 year amortization period based on the depreciation study and consistent with Petersburg Unit 2 assets.

(10) The pro forma annual amortization was calculated by dividing the deferred depreciation for the Eagle Valley CCGT and the Harding Street 5 & 6 Refueling by the remaining useful life.

(11) The pro forma annual amortization was calculated by dividing the deferred post in-service AFUDC for the Eagle Valley CCGT and the Harding Street 5 & 6 Refueling by the remaining useful life.

(12) The pro forma annual amortization was calculated by dividing the electric vehicle deferred asset by a 10 year amortization period (agrees to prior rate case).

(13) The pro forma annual amortization was calculated by dividing the original deferred Harding Street 7 Preservation costs of $4,233,695.40 by a ten year amortization period (agrees to prior rate case).

(14) The pro forma annual amortization was calculated by dividing the deferred 20% HS7 Gas Conversion and NPDES Revenue Requirements by a 3 year amortization period.

(15) The pro forma annual amortization was calculated by dividing the deferred 20% NAAQS-DBA, CCR Bottom Ash, and NAAQS-Other Revenue Requirements by a 3 year amortization period.

(16) The pro forma annual amortization for Petersburg Unit 1 & 2 is equal to the depreciation in the Settlement Agreement in Cause No. 45502.

(16.1) Amortized over 10 years.

(17) The pro forma annual amortization was calculated by dividing the deferred depreciation for TDSIC by the useful life (36.3 years) as approved in the IURC Orders from Cause No. 45264, TDSIC 1.

(18) The pro forma annual amortization was calculated by dividing the deferred post in-service AFUDC for the TDSIC projects by the useful life (36.3 years) as approved in the IURC Orders in Cause No. 45264, TDSIC 1.

(19) The pro forma annual amortization was calculated by dividing the deferred 20% TDSIC Distribution and TDSIC Transmission Revenue Requirements by a 3 year amortization period.

(20) The pro forma annual amortization for the Eagle Valley outage repair capital expenditures was calculated by dividing the costs by a 25 year amortization period for the Settlement Agreement in IURC Cause No. 38703 FAC 133S1.

(21) The pro forma annual amortization for the COVID-19 deferral was calculated by dividing the deferral by a 3 year amortization period.

(22) See Financial Exhibit AESI-OPER, Schedule DEPR, Line 13.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper RB9.

AES Indiana
Statements of Electric Operating Income for the Twelve Months Ended December 31, 2022
Per Books and Jurisdictional Pro Forma at Present and Proposed Rates
(Thousands of Dollars)

Line No.		Twelve Months Ended 12/31/2022 Per Books (Col. 1)	At Present Rates Adjustments (Col. 2)	At Present Rates Pro Forma (Col. 3)	At Proposed Rates Adjustments (Col. 4)	At Proposed Rates Pro Forma (Col. 5)	Line No.
1	Operating revenues	$ 1,791,546	$ (219,947)	$ 1,571,599	$ 71,037	$ 1,642,636	1
	Operating expenses:						
2	Operation and maintenance expenses	1,242,330	(207,195)	1,035,135	376	1,035,511	2
3	Depreciation and amortization expense	272,093	29,312	301,405	—	301,405	3
4	Taxes-other than income taxes	33,464	(6,470)	26,994	—	26,994	4
5	Total operating expenses other than income taxes	1,547,886	(184,352)	1,363,534	376	1,363,910	5
6	Net operating income before income taxes	243,660	(35,595)	208,065	70,661	278,726	6
	Income taxes:						
7	Federal income taxes - current	31,385	(334)	31,051	14,112	45,163	7
8	State income taxes - current	8,168	(658)	7,510	3,462	10,972	8
9	Federal income taxes - deferred	(7,278)	(4,241)	(11,519)	—	(11,519)	9
10	State income taxes - deferred	125	(1,985)	(1,860)	—	(1,860)	10
11	Income tax credit adjustments	(3)	—	(3)	—	(3)	11
12	Total income taxes	32,398	(7,218)	25,179	17,574	42,753	12
13	Net utility operating income	$ 211,262	$ (28,377)	$ 182,885	$ 53,087	$ 235,972	13

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OPINC-S-R

AES Indiana
Summary of Electric Operating Revenue for the Twelve Months Ended December 31, 2022
Per Books and Pro Forma at Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Per Books	At Present Rates Adjustments (1)	At Present Rates Pro Forma	At Proposed Rates Adjustments (2)	At Proposed Rates Pro Forma	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	
1	Residential revenues	$ 697,060	$ (40,260)	$ 656,800	$ 48,475	$ 705,275	1
2	Small commercial & industrial revenues	$ 242,173	$ (6,605)	$ 235,568	$ 9,301	$ 244,869	2
3	Large commercial & industrial revenues	$ 643,606	$ (35,957)	$ 607,649	$ 14,806	$ 622,455	3
4	Lighting	$ 17,628	$ (98)	$ 17,530	$ 1,504	$ 19,034	4
5	Electric vehicle public charging stations	$ 30	$ —	$ 30	$ —	$ 30	5
6	Off-system sales	$ 148,517	$ (119,905)	$ 28,612	$ —	$ 28,612	6
7	Capacity sales	$ 11,750	$ (11,750)	$ —	$ —	$ —	7
8	Total sales of electric energy	$ 1,760,764	$ (214,575)	$ 1,546,189	$ 74,086	$ 1,620,275	8
	Other Electric Revenues						
9	Rents	$ 3,368	$ (130)	$ 3,238	$ —	$ 3,238	9
10	Other customer charges	$ 16,875	$ —	$ 16,875	$ (3,048)	$ 13,827	10
11	Miscellaneous revenue	$ 10,539	$ (5,242)	$ 5,297	$ —	$ 5,297	11
12	Total other electric revenues	$ 30,782	$ (5,372)	$ 25,410	$ (3,048)	$ 22,362	12
13	Total electric operating revenues (See Exhibit AESI-OPER, Sch. OPINC, Line 1)	$ 1,791,546	$ (219,947)	$ 1,571,599	$ 71,037	$ 1,642,636	13

(1) Adjustments shown on AES Indiana Financial Exhibit AESI-OPER, Schedule REV2-R
(2) Adjustments shown on AES Indiana Financial Exhibit AESI-OPER, Schedule REV10-S-R CORRECTED

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV1-S-R CORRECTED.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Taking Per Books to Pro Forma at Present Rates
(Thousands of Dollars)

Line No.	Description	Adjustment Schedules Sch. REV3	Sch. REV4	Sch. REV5	Sch. REV6	Sch. REV7	Sch. REV8	Sch. REV9	Total Adjustments (1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	
1	Residential revenues	$ (105,414)	$ (17,813)	$ 82,967	$ —	$ —	$ —	$ —	$ (40,260)	1
2	Small commercial & industrial revenues	(36,541)	(4,964)	34,900	—	—	—	—	(6,605)	2
3	Large commercial & industrial revenues	(120,949)	(3,323)	88,315	—	—	—	—	(35,957)	3
4	Lighting	(945)	(8)	855	—	—	—	—	(98)	4
5	Electric vehicle public charging stations	—	—	—	—	—	—	—	—	5
6	Off-system sales	—	—	—	(119,905)	—	—		(119,905)	6
7	Capacity sales	—	—	—	—	—	—	(11,750)	(11,750)	7
8	Total sales of electric energy	(263,849)	(26,108)	207,036	(119,905)	—	—	(11,750)	(214,575)	8
	Other Electric Revenues									
9	Rents	—	—	—	—	(130)	—	—	(130)	9
10	Other customer charges	—	—	—	—	—	—	—	—	10
11	Miscellaneous revenue	—	—	—	—	—	(5,242)	—	(5,242)	11
12	Total other electric revenues	—	—	—	—	(130)	(5,242)	—	(5,372)	12
13	Pro forma revenue adjustments	$ (263,849)	$ (26,108)	$ 207,036	$ (119,905)	$ (130)	$ (5,242)	$ (11,750)	$ (219,947)	13

(1) See Schedule REV1, Column 2

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV2.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Taking Total Retail Revenue to Retail Basic Rates Revenue
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Per Books Total Retail Revenue (Col. 1)	Less: Twelve Months Ended 12/31/2022 Per Books Rider 6 Fuel Revenue (Col. 2)	Less: Twelve Months Ended 12/31/2022 Per Books Rider 22 DSM Revenue (Col. 3)	Less: Twelve Months Ended 12/31/2022 Per Books Rider 20 ECR Revenue (Col. 4)	Less: Twelve Months Ended 12/31/2022 Per Books Rider 21 Green Revenue (Col. 5)	Less: Twelve Months Ended 12/31/2022 Per Books Rider 3 TDSIC (Col. 6)	Sub-Total (Col. 7)	Line No.
1	Residential revenues	$ 697,060	$ (80,282)	$ (26,500)	$ (1,223)	$ (271)	$ (10,364)	$ 578,420	1
2	Small commercial & industrial revenues	242,173	(28,449)	(8,990)	(257)	(69)	(3,072)	201,337	2
3	Large commercial & industrial revenues	643,606	(99,319)	(26,733)	(567)	(1,202)	(6,240)	509,545	3
4	Lighting	17,628	(482)	(434)	2	—	(154)	16,559	4
5	Electric vehicle public charging stations	30	—	—	—	—	—	30	5
6	Total	$ 1,600,497	$ (208,532)	$ (62,657)	$ (2,045)	$ (1,542)	$ (19,829)	$ 1,305,891	6
7	Pro forma revenue adjustments		$ (208,532)	$ (62,657)	$ (2,045)	$ (1,542)	$ (19,829)	$ (294,605)	7

AES Indiana
Summary of Electric Operating Revenue Adjustments
Taking Total Retail Revenue to Retail Basic Rates Revenue
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Less: Twelve Months Ended 12/31/2022 Per Books Rider 26 RTO Revenue	Less: Twelve Months Ended 12/31/2022 Per Books Rider 25 OSS Revenue	Less: Twelve Months Ended 12/31/2022 Per Books Rider 24 CAP Revenue	Sub-Total Page 2	Sub-Total from Page 1 Column 6	Twelve Months Ended 12/31/2022 Per Books Basic Rate Revenue (1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
8	Residential revenues	$ (802)	$ 14,464	$ (435)	$ 13,226	$ 578,420	$ 591,646	8
9	Small commercial & industrial revenues	(268)	4,802	(240)	4,294	201,337	205,632	9
10	Large commercial & industrial revenues	(810)	14,651	(729)	13,112	509,545	522,657	10
11	Lighting	(7)	140	(10)	123	16,559	16,683	11
12	Electric vehicle public charging stations	—	—	—	—	30	30	12
13	Total	$ (1,887)	$ 34,057	$ (1,414)	$ 30,757	$ 1,305,891	$ 1,336,648	13
14	Pro forma revenue adjustments	$ (1,887)	$ 34,057	$ (1,414)	$ 30,757	$ (294,605)		14
15	Total pro forma revenue adjustments (See Schedule REV2, Column 1)					$ (263,849)		15

(1) To Schedule REV4, Column 1

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV3.

AES Indiana
Summary of Electric Retail Basic Rate Revenue Adjustments
for Billing Determinants, Weatherization, Customer Annualization, DSM Installations Annualization
and to Remove Unbilled Revenues
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Per Books Basic Rate Revenue (1)	Adjustment for Weather Normalization (2)	Adjustment for Customer Annualization (3)	Adjustment for DSM Installations Annualization (4)	Adjustment for Billing Determinants Full Year at 12/31/2022 Rates (5)	Twelve Months Ended 12/31/2022 Adjusted Basic Rate Revenue (6)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
1	Residential revenues	$ 591,646	$ (2,212)	$ (3,031)	$ (610)	$ (11,959)	$ 573,833	1
2	Small commercial & industrial revenues	205,632	(345)	(1,107)	(955)	(2,557)	200,667	2
3	Large commercial & industrial revenues	522,657	(55)	(1,364)	(1,459)	(445)	519,334	3
4	Lighting	16,683	—	154	—	(162)	16,675	4
5	Electric vehicle public charging stations	30	—	—	—	—	30	5
6	Total	$ 1,336,648	$ (2,612)	$ (5,348)	$ (3,025)	$ (15,123)	$ 1,310,540	6
7	Pro forma revenue adjustments		$ (2,612)	$ (5,348)	$ (3,025)	$ (15,123)		7
8	Total pro forma revenue adjustments (See Schedule REV2, Column 2)					$ (26,108)		8

(1) From Schedule REV3, Page 2, Column 6

(2) Provided by AES Indiana Witness Baker, with support from AES Indiana Witness Fox

(3) Provided by AES Indiana Witness Baker

(4) Provided by AES Indiana Witness Baker. This amount adjusts the test year to reflect a full year of lost revenues for the DSM measures installed during the test year, provided by AES Indiana Witness Baker.

(5) Adjustment to true-up revenues to match expected billing determinants for test year, provided by AES Indiana Witness Baker.

(6) To Schedule REV5, Page 1, Column 1

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV4.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Adding Back Pro Forma at Present Rates Rider Revenues
to Achieve Total Retail Revenue Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Adjusted Basic Rate Revenue (1) (Col. 1)	Add: Pro Forma at Present Rates Rider 6 Fuel Revenue (2) (Col. 2)	Add: Pro Forma at Present Rates Rider 20 ECR Revenue (3) (Col. 3)	Add: Pro Forma at Present Rates Rider 22 DSM Lost Revenue (4) (Col. 4)	Sub-Total to Page 2 (Col. 5)	Line No.
1	Residential revenues	$ 573,833	$ 31,211	$ 507	$ 8,266	$ 613,817	1
2	Small commercial & industrial revenues	200,667	10,693	168	9,794	221,323	2
3	Large commercial & industrial revenues	519,334	37,022	514	6,333	563,203	3
4	Lighting	16,675	351	5	87	17,118	4
5	Electric vehicle public charging stations	30	—	—	—	30	5
6	Total	$ 1,310,540	$ 79,277	$ 1,194	$ 24,479	$ 1,415,490	6
7	Pro forma revenue adjustments		$ 79,277	$ 1,194	$ 24,479	$ 104,950	7

(1) From Schedule REV4, Column 6
(2) This amount represents normalized KWh sales multiplied by the proposed change in the base cost of fuel. See REV5-WP1.
(3) This amount reflects annualized ECR revenue for projects moving into base rates and therefore excludes the return AESI accrued on construction work in progress for its NAAQS-Other, projects during the test year. See REV5-WP2.
(4) This amount reflects the annualized lost revenues from DSM programs installed prior to the end of the test year moving into base rates. See REV5, WP3.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Adding Back Pro Forma at Present Rates Rider Revenues
to Achieve Total Retail Revenue Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Sub-Total from Page 1 (Col. 1)	Add: Pro Forma at Present Rates Rider 24 CAP Revenue (5) (Col. 2)	Add: Pro Forma at Present Rates Rider 25 OSS Margins (6) (Col. 3)	Add: Pro Forma at Present Rates Rider 26 RTO Revenue (7) (Col. 4)	Add: Pro Forma at Present Rates Rider 3 TDSIC Revenue (8) (Col. 5)	Total Electric Adjusted Basic Rate Revenue Pro Forma at Present Rates to Page 3 (Col. 6)	Line No.
1	Residential revenues	$ 613,817	$ 12,879	$ (5,220)	$ 591	$ 20,448	$ 642,515	1
2	Small commercial & industrial revenues	221,323	4,275	(1,733)	196	6,787	230,848	2
3	Large commercial & industrial revenues	563,203	13,040	(5,285)	598	20,703	592,259	3
4	Lighting	17,118	124	(50)	6	197	17,395	4
5	Electric vehicle public charging stations	30	—	—	—	—	30	5
6	Total	$ 1,415,490	$ 30,318	$ (12,288)	$ 1,391	$ 48,135	$ 1,483,046	6
7	Pro forma revenue adjustments	$ 104,950	$ 30,318	$ (12,288)	$ 1,391	$ 48,135	$ 172,506	7

(5) This amount reflects the proposed change in the base cost of capacity net revenue and expense benchmark. See REV5-WP5.
(6) This reflects that the proposed change in the off-system sales ("OSS") margin benchmark. See REV5-WP6.
(7) This amount reflects the proposed change in the base cost of net MISO expense benchmark. See REV5-WP7.
(8) This amount reflects annualized TDSIC revenue for projects moving into base rates and therefore excludes the return AES Indiana accrued on construction work in progress for its TDSIC projects during the test year. See REV5-WP8.

AES Indiana
Summary of Electric Operating Revenue Adjustments
Adding Back Pro Forma at Present Rates Rider Revenues
to Achieve Total Retail Revenue Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Total Electric Adjusted Basic Rate Revenue Pro Forma at Present Rates from Page 2	Add: Pro Forma at Present Rates Rider 20 ECR Revenue (9)	Add: Pro Forma at Present Rates Rider 22 DSM Revenue (10)	Add: Pro Forma at Present Rates Rider 21 Green Revenue (11)	Add: Pro Forma at Present Rates Rider 26 TDSIC Revenue (12)	Total Electric Adjusted Retail Revenue Pro Forma at Present Rates	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
1	Residential revenues	$ 642,515	$ —	$ 14,014	$ 271	$ —	$ 656,800	1
2	Small commercial & industrial revenues	230,848	—	4,651	69	—	235,567	2
3	Large commercial & industrial revenues	592,259	—	14,188	1,202	—	607,649	3
4	Lighting	17,395	—	135	—	—	17,530	4
5	Electric vehicle public charging stations	30	—	—	—	—	30	5
6	Total	$ 1,483,046	$ —	$ 32,988	$ 1,542	$ —	$ 1,517,577	6
7	Pro forma revenue adjustments (See Schedule REV2, Column 3)	$ 172,506	$ —	$ 32,988	$ 1,542	$ —	$ 207,036	7

(9) No environmental projects are remaining in the ECR, therefore no offsetting revenue has been included here.
(10) This amount reflects the test year DSM expenses (net of deferrals) recorded to expense accounts. See REV5-WP9.
(11) From Schedule REV3, Page 1, Column 5
(12) Pro forma test year expenses related to TDSIC projects in-service after 12/31/2022 net to zero, therefore no offsetting revenue has been included here.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV5.

AES Indiana
Summary of Off-System Sales ("OSS")
Total Revenue Per Books and Pro Forma Net Margin at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	MISO Off-System Sales: Not Attributed to LWP (1) (Col. 1)	MISO Off-System Sales: Sales Attributed to LWP Production (Col. 2)	MISO Off-System Sales: LWP OSS Sales to be passed back through OSS tracker (2) (Col. 3)	MISO Off-System Sales: Total (Col. 4)	Reclassifications: OM2 (Col. 5)	Reclassifications: OM4 (Col. 6)	Reclassified Total Margins (Col. 7)	Line No.
1	OSS revenues	$ 131,611	$ 16,906		$ 148,517	$ (76,227)	$ (14,503)	$ 57,787	1
2	Fuel costs	67,685	8,542		76,227	$ (76,227)	$ —		2
3	Production costs	12,928	1,575		14,503	—	(14,503)		3
4	Total costs	80,612	10,118	—	90,730	$ (76,227)	$ (14,503)		4
5	Total OSS margins	50,999	6,788	—	57,787			$ 57,787	5
6	LWP margins returned via FAC (1)	—	(6,788)	6,788	—			—	6
7	OSS margins not attributed to LWP	$ 50,999	$ —	$ 6,788	$ 57,787			57,787	7
8	Pro forma adjustment to margins							(29,175)	8
9	Pro forma margins for OSS to be embedded in retail rates							$ 28,612	9
10	Breakout of total pro forma adjustment								10
11	Reclassify OSS fuel against revenues				$ (76,227)				11
12	Reclassify OSS production costs against revenues				(14,503)				12
13	Adjust OSS margin to pro forma level				(29,175)				13
14	Pro forma adjustment reflects the wholesale margin embedded in retail rates (See Schedule REV2, Column 4, Line 6)				$ (119,905)				14

(1) LWP is an abbreviation for Lakefield Wind Production. In accordance with the IURC order in Cause No. 43740, In the test year AES Indiana reduced the fuel costs charged to its jurisdictional retail customers by an amount equal to its estimated wholesale margin attributable to production from its Lakefield Wind Purchase Power Agreement.

(2) See AES Indiana Witness Steiner's testimony regarding the proposed change to the treatment of LWP OSS margin. AES Indiana is proposing to include OSS margin attributable to LWP in the OSS tracker instead of the FAC tracker. This adjustment is needed to reflect the total test year OSS margin REV6 and there is no LWP credit included on OM2.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV6.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule REV7

AES Indiana
Summary of Electric Rent Revenue
Per Books and Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustments	Pro Forma Total Electric at Present Rates	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Georgetown Units rent	$ 486	$ —	$ 486	1
2	Pole contact rental	2,036	(128)	1,908	2
3	Lease rent revenue	847	(2)	845	3
4	Total	$ 3,368	$ (130)	$ 3,238	4
5	Pro forma adjustment (See Schedule REV2, Column 5, Line 9)		$ (130)		5

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV7.

AES Indiana
Summary of Miscellaneous Electric Revenue
Per Books and Pro Forma at Present Rates
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Twelve Months Ended 12/31/2022 Per Books (Col. 1)	Pro Forma Adjustments (Col. 2)		Pro Forma Total Electric at Present Rates (Col. 3)	Line No.
1	Distribution Ancillary Revenue	$ 269	$ —		$ 269	1
2	MISO Transmission Revenue	7,082	(3,459)	(1)	3,623	2
3	Remove Deferrals for RTO (Over)/Under Collection	(5,011)	5,011		—	3
4	Remove MISO Non-Jurisdictional Revenue	2,431	(2,431)	(2)	—	4
5	Remove Gains from Disposition of Allowances	4,358	(4,358)		—	5
6	MISO Balancing Authority Credits (See Schedule OM13 Line 12)	758	(5)		753	6
7	MISO Deferred Expense Amortization (See Schedule OM14 Line 13)	653	—		653	7
8	Total	$ 10,539	$ (5,242)		$ 5,297	8
9	Pro forma adjustment (See Schedule REV2, Column 6, Line 11)		$ (5,242)			9

(1) Adjust to reflect pro-forma MISO Jurisdictional Revenues.

(2) Provided by AES Indiana Witness Aliff, to remove the non-jurisdictional revenue associated with the plant in service removed from rate base on AES Indiana Financial Exhibit AESI-RB, Schedule RB5.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV8.

AES Indiana
Pro Forma Adjustment to Capacity Sales
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	(Col. 1)	Line No.
1	Pro forma capacity sales	$ —	1
2	Per books capacity sales during the twelve months ended December 31, 2022	11,750	2
3	Total pro forma adjustment (See Schedule REV2, Column 7, Line 7)	$ (11,750)	3

Note: Capacity sales and expense are presented as a net expense on OM3.

AES Indiana
Electric Operating Revenue Adjustment
Taking Pro Forma at Present Rates
to Pro Forma at Proposed Rates
(Thousands of Dollars)

Line No.	Description		Revenue from Proposed Increase (Col. 1)	Line No.
1	Residential revenues	$	48,475	1
2	Small commercial & industrial revenues	$	9,301	2
3	Large commercial & industrial revenues	$	14,806	3
4	Lighting	$	1,504	4
5	Electric vehicle public charging stations	$	—	5
6	Off-system sales	$	—	6
7	Capacity sales	$	—	7
8	Total sales of electric energy	$	74,086	8
	Other Electric Revenues			
9	Rents	$	—	9
10	Other customer charges	$	(3,048)	10
11	Miscellaneous revenue	$	—	11
12	Total other electric revenues	$	(3,048)	12
13	Total electric operating revenues	$	71,037	13
14	Pro forma adjustment (See Schedule REV1, Column 4)	$	71,037	14

Note: This exhibit agrees to AES Indiana Witness BR, Attachment 4, Page 2 of 2, Column O.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper REV10-S-R CORRECTED.

AES INDIANA
Summary of Pro Forma Adjustments to Electric Operation and Maintenance Expense for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.	Description	Exhibit AESI-OPER Adjustment Schedule Reference	Pro Forma Adjustments: Total Electric At Present Rates	Pro Forma Adjustments: Total Electric At Proposed Rates	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1					1
2	Cost of fuel and purchased power	OM2	$ (226,079)	$ —	2
3	Capacity costs	OM3	17,238	—	3
4	Off-system sales power production costs	OM4	(14,503)	—	4
5	Generation consumables	OM5	(10,662)	—	5
6	Transportation expenses	OM6	(603)	—	6
7	Non-outage operating and maintenance costs	OM7	(13,517)	—	7
8	Seasonal NOx emission allowance expense	OM8	(914)	—	8
9	Obsolete/damaged materials and supplies inventory write-off expense	OM9	(634)	—	9
10	Non-jurisdictional MISO MTEP operating and maintenance expenses	OM10	(953)	—	10
11	Storm expenses	OM11	(2,533)	—	11
12	Vegetation management costs	OM12	10,214	—	12
13	MISO non-fuel costs	OM13	369	—	13
14	MISO deferred expense amortization	OM14	—	—	14
15	Wages of AES Indiana and AES U.S. Services, LLC employees	OM15	14,239	—	15
16	Employer insurance benefits of AES Indiana and AES U.S. Services, LLC employees	OM16	1,834	—	16
17	Pension expense and OPEB	OM17	13,580	—	17
18	ACE Project	OM18	8,127	—	18
19	Image-building advertising costs	OM19	(2,205)	—	19
20	Injuries and damages expense	OM20	235	—	20
21	Amortization of rate case expense	OM21	750	—	21
22	Miscellaneous expense adjustments	OM22	(2,941)	—	22
23	AES U.S. Services, LLC occupancy and non-labor costs	OM23	(855)	—	23
24	ECR, TDSIC Tracker Items	OM24	(922)	—	24
25	Property and other casualty insurance expense	OM25	4,864	—	25
26	Write off of preliminary survey and investigation charges	OM26	(325)	—	26
27	Uncollectible accounts expense	OM27	(1,626)	271	27
28	Public utility fee	OM28	628	105	28
29	Total pro forma adjustments (See Exhibit AESI-OPER, Schedule OPINC, Line 2, Columns 3 and 5, respectively)		$ (207,195)	$ 376	29

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM2-S-R

AES Indiana
Pro Forma Adjustment to Cost of Fuel and Purchased Power
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars, Except Base Cost of Fuel Increment)

The following pro forma adjustment reflects the change in total electric cost of fuel and purchased power, taking into consideration changes in pro forma MWh sales, power purchases, and power sales.

Line No.		(Col. 1)	(Col. 2)	Line No.
	MWh Source			
1	Coal and oil generation		6,316,299	1
2	Gas generation		9,641,261	2
3	Other generation- internal combustion			3
	Purchases through MISO:			
4	Wind purchase power agreement (PPA) purchases		747,509	4
5	Non-Wind PPA market purchases		394,025	5
6	Purchased power other than MISO (solar)		144,205	6
	Less:			
7	Energy losses and company use		604,181	7
8	Inter-System sales through MISO		3,619,393	8
9	Total MWh source		13,019,725	9
	Fuel Cost $			
10	Coal and oil generation		$ 184,752	10
11	Gas generation		319,912	11
12	Other generation- internal combustion			12
	Purchases through MISO:			
13	Wind purchase power agreement purchases		51,237	13
14	Non-Wind PPA market purchases		14,509	14
15	MISO components of cost of fuel		26,821	15
16	Purchased power other than MISO (solar)		23,503	16
	Less:			
17	Inter-System sales through MISO		107,200	17
18	Transmission losses		5,417	18
19	Pro forma total retail electric cost of fuel		508,117	19
20	Actual total electric coal, oil, gas, and purchased power costs for the twelve months ended December 31, 2022		734,196	20
21	Pro forma adjustment to retail fuel cost (See Schedule OM1)		$ (226,079)	21
	Breakout of retail and wholesale fuel costs			
22	Pro forma total retail electric cost of fuel (from Line 19)	$ 508,117		22
23	Actual retail fuel cost	(657,969)		23
24	Pro forma adjustment for retail fuel cost	(149,852)		24
25	Reclassify actual off-system sales fuel cost (See Schedule REV6)	(76,227)		25
26	Total pro forma adjustment to fuel costs	$ (226,079)		26
27	New base cost of fuel per kWh (line 20 / line 9)		$ 0.039027	27

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM2.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM3

AES Indiana
Pro Forma Adjustment to Capacity Costs
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects the expected change in capacity costs.

Line No.			(Col. 1)	Line No.
1	Pro forma capacity costs	$	19,030	1
2	Per books capacity costs expensed during the twelve months ended December 31, 2022		1,792	2
3	Total pro forma adjustment (See Schedule OM1)	$	17,238	3

Note: Capacity sales and expense are presented as a net expense on OM3.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM3.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM4

AES Indiana
Pro Forma Adjustment to Off-System Sales Power Production Costs
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects the removal of off-system sales power production costs from AESI's jurisdictional operating expenses.

Line No.			(Col. 1)	Line No.
1	Pro forma off-system sales power production costs	$	—	1
2	Actual off-system sales power production costs adjustment (See Schedule REV6)		14,503	2
3	Total pro forma adjustment (See Schedule OM1)	$	(14,503)	3

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM4.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM5-S-R

AES Indiana
Pro Forma Adjustment to
Generation Consumables Variable Expenses
(Thousands of Dollars)

The following pro forma adjustment is to reflect non-labor changes to the retail cost of ganeration consumables.

Line No.		Pro Forma O & M (Col. 1)	Actual Generating Unit Consumables Cost Per Books for the Twelve Months Ended December 31, 2022 (Col. 2)	Pro Forma Adjustment (Col. 3)	Line No.
1	Harding Street Generating Station	$ 1,029	$ 649	$ 380	1
2	Eagle Valley CCGT	1,198	598	600	2
3	Petersburg	13,287	16,879	(3,592)	3
4	Petersburg Unit 2	—	8,050	(8,050)	4
5	Total pro forma adjustment (See Schedule OM1)	$ 15,514	$ 26,176	$ (10,662)	5

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM5.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM6

AES Indiana
Pro Forma Adjustment to Exclude Certain Transportation Expense
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects the removal of vehicle rental fees incurred in the test year. The rental agreements ended in May of 2022 and were not renewed.

Line No.		Pro Forma Transportation Expense	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Vehicle Rental Fees	$ —	$ 603	$ (603)	1

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM6

AES Indiana
Pro Forma Adjustment to
Non-Outage Operating and Maintenance ("O&M") Costs

(Thousands of Dollars)

The following pro forma adjustment is to adjust non-outage operating and maintenance costs (excluding base labor, overtime and benefits) to expected ongoing levels

Line No.		Pro Forma O & M Cost	Generating Unit O & M Cost Per Books for the Twelve Months Ended 12/31/2022	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Harding Street Generating Station	$ 8,717	$ 8,717	$ —	1
2	Eagle Valley CCGT	5,412	5,412	—	2
3	Eagle Valley Insurance Event 1	—	67	(67)	3
4	Eagle Valley Insurance Event 2	—	1,258	(1,258)	4
5	Petersburg (Petersburg Units 3 & 4 Only)	38,426	38,426	—	5
6	Petersburg Unit 2	—	12,192	(12,192)	6
7	Power Supply Support	1,553	1,553	—	7
8	Total pro forma adjustment (See Schedule OM1)	$ 54,108	$ 67,625	$ (13,517)	8

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM7.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM8

AES Indiana
Pro Forma Adjustment to
Seasonal NOx Emission Allowance Expense
(Thousands of Dollars, Except Per Allowance Pricing)

The following adjustment represents the impact of expected changes to AESI's emission allowance expense for Environmental Protection Agency ("EPA") Seasonal NOx allowances. (1)

Line No.			(Col. 1)	Line No.
1	Projected tons of seasonal NOx emissions		1,768	1
2	Less: 2022 allowances allotted from EPA at no cost		1,836	2
3	Projected shortfall, zero if negative		0	3
4	Current market pricing for 2022 NOx emissions (in $ per ton)	$	9,500	4
5	Projected seasonal NOx emission expense		0	5
6	Less: Per books expense for the twelve months ended December 31, 2022		914	6
7	Pro forma adjustment to seasonal NOx expense (See Schedule OM1)	$	(914)	7

(1) Seasonal NOx emissions are emissions from May through September of each calendar year.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM8.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM9

AES Indiana
Pro Forma Adjustment to
Obsolete/Damaged Materials and Supplies Inventory Write-Off Expense
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects a normalization of write-offs for obsolete/damaged materials and supplies inventory.

Line No.		Amount (Col. 1)	Line No.
1	Actual write off for the 12 month period ended December 31, 2020	$ 182	1
2	Actual write off for the 12 month period ended December 31, 2021	2,630	2
3	Actual write off for the 12 month period ended December 31, 2022	2,357	3
4	Total write off for the 3 year period ended December 31, 2022	$ 5,169	4
5	3-year average write off of obsolete/damaged inventory	$ 1,723	5
6	Per books write-offs during the twelve months ended December 31, 2022	2,357	6
7	Pro forma adjustment (See Schedule OM1)	$ (634)	7

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM9.

AES Indiana
Pro Forma Adjustment to Remove Non-Jurisdictional MISO MTEP (1) Operation and Maintenance Expenses
(Thousands of Dollars)

The following pro forma adjustment removes non-jurisdictional MISO MTEP expenses in conjunction with the transmission plant removed on AES IN Financial Exhibit AES IN-RB, Schedule RB5.

Line No.		(Col. 1)	Line No.
1	Total pro forma non-jurisdictional MISO MTEP O & M expense to be included in basic rates	$ —	1
2	Amount charged to electric operating expense for the twelve months ended December 31, 2022	953	2
3	Pro forma adjustment (See Schedule OM1)	$ (953)	3

(1) Midcontinent Independent System Operator, Inc. ("MISO") Transmission Expansion Plan ("MTEP")

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM11

AES Indiana
Pro Forma Adjustment to Storm Expenses
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects a normalization of storm costs. The adjustment also includes the amortization of the pro forma Storm Reserve balance.

Line No.		(Col. 1)	(Col. 2)	Line No.
1	Pro forma level 1 & 2 storm cost expense, excluding base labor and benefits, based upon the average experienced during the period of January 1, 2020 through December 31, 2022	$ 11,351		1
2	Less: Per books storm costs, excluding base labor and benefits, expensed during the twelve months ended December 31, 2022	12,409		2
3	Pro forma adjustment to level 1 & 2 storm expense		$ (1,058)	3
4	Pro forma level 3 & 4 non-capital storm costs, excluding base labor and benefits, based upon the current benchmark approved in the prior case adjusted for the price index	$ 1,908		4
5	Less: Base amount recognized in distribution expense account during the twelve months ended December 31, 2022 (1)	$ 1,363		5
6	Pro forma adjustment for base level 3 & 4 storms expense		$ 545	6
7	Net increase from test year experience		$ (513)	7
8	Balance of the storm reserve account at December 31, 2022	$ (4,696)		8
9	Add: Additional reserve accrual through December 31, 2023	$ (1,363)		9
10		$ (6,059)		10
11	3-year amortization	/ 3		11
12			$ (2,020)	12
13	Total pro forma expense adjustment (See Schedule OM1)		$ (2,533)	13

(1) Per IURC Cause No. 45029.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM11.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM12-S-R

AES Indiana
Pro Forma Adjustment to Distribution Vegetation Management Costs
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects expected pricing and scope changes to distribution vegetation management costs.

Line No.		Pro Forma Costs	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Total pro forma expense adjustment (See Schedule OM1)	$ 25,247	$ 15,033	$ 10,214	1

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM12.

AES Indiana
Pro Forma Adjustment to
MISO Non-Fuel Costs
(Thousands of Dollars)

The following pro forma adjustment reflects the expected increase to MISO non-fuel costs.

Line No.		Actual Per Book MISO Costs for the Twelve Months Ended 12/31/2022 (Col. 1)	Pro Forma Annual MISO Costs (Col. 2)	Pro Forma Adjustment (See Schedule OM1) (Col. 3)	Line No.
	The following categories represent the pro forma annual level of Midcontinent Independent System Operator, Inc. ("MISO") non-fuel costs (1):				
1	Def Cost MISO Net Billings (Schedule 10)	$ 2,954	$ 2,880	$ (74)	1
2	MISO Market Admin Fees (Schedule 17)	2,323	2,567	245	2
3	FTR Market Admin Fees Retail (Schedule 16)	77	73	(4)	3
4	MISO Socialized and Uplift Costs	2,900	3,159	259	4
5	MISO Balancing Authority Costs (Schedule 24)	398	361	(38)	5
6	MISO Balancing Authority Credits (Schedule 24)	(758)	(753)	5	6
7	MISO RSG Over Benchmark	358	70	(288)	7
8	MISO Transmission Expansion (Schedule 26 and 26A)	25,433	25,550	117	8
9	MISO Transmission Expense (Schedule 2 &11)	3,191	—	(3,191)	9
10	MISO FERC fees	1,298	1,134	(164)	10
11	Subtotal	$ 38,173	$ 35,040	$ (3,133)	11
12	Remove MISO Balancing Authority Credits (See Schedule REV 8)	758	753	(5)	12
13	Remove Deferrals for RTO (Over)/Under Collection	(3,507)	—	3,507	13
14	Total	$ 35,424	$ 35,793	$ 369	14

(1) See related revenue on AESI-OPER, Schedule REV8.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM13.

AES Indiana
Pro Forma Adjustment to MISO Deferred Expense Amortization
(Thousands of Dollars)

The following adjustment represents the recognition of Midcontinent Independent System Operator, Inc. ("MISO") nonfuel costs deferred through the effective date of the rates approved in the IURC order in Cause No. 44576.

Line No.	Description	Unamortized Balance (Col. 1)	Amortization Period (Col. 2)	Pro Forma Annual Amortization (Col. 3)	Less: Amortization Per Books for the Twelve Months Ended 12/31/2022 (Col. 4)	Pro Forma Amortization Adjustment (See Schedule OM1) (Col. 5)	Line No.
	MISO deferred in accordance with the IURC orders in Cause Nos. 42266, 42685 and 42962						
1	Total deferred MISO nonfuel costs	$ 134,952					1
2	Less: Resettlements by MISO per FERC Order in EL14-12	1,029					2
3	Net recoverable MISO nonfuel charges	$ 133,923	10	$ 13,392	$ 13,392		3
4	Annual Amortization by FERC Account						4
5	565000			$ 3,655			5
6	575200			3,097			6
7	557000			4,153			7
8	561200			391			8
9	557000			337			9
10	566000			2,318			10
11	561200			94			11
12	Total Amortization of OM Expense			$ 14,045	$ 14,045	(0)	12
13	Annual Amortization to Revenue FERC 456100 (See Schedule REV8)			$ (653)	$ (653)		13
14	Total Amortization to FERC 182300 (Agrees to Line 3 Column 3)			$ 13,392	$ 13,392		14
15	Less: Accumulated amortization at December 31, 2022 representing amounts received through basic rates and charges.	$ 86,048					15
16	Total unamortized balance	$ 47,875					16

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM14.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM15-S-R

AES Indiana
Pro Forma Adjustment to Operation and Maintenance Expenses for Wages of AES Indiana and AES U.S. Services, LLC (AES Services) Employees
(Thousands of Dollars)

The following adjustment represents the net impact of changes to AES Indiana and AES U.S. Services, LLC (AES Services) labor costs

Line No.		Total Electric Per Books (Col. 1)	Pro Forma (Col. 2)	Adjustments (Col. 3)	Line No.
1	Labor costs (AES Indiana employees)	$ 113,540	$ 124,565	$ 11,025	1
2	Labor costs (from AES Services)	19,760	22,974	3,213	2
3	Total labor, AES Indiana and AES Services costs	$ 133,300	$ 147,539		3
4	Pro forma adjustment (See Schedule OM1)			$ 14,239	4

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM15.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM16

AES Indiana
Pro Forma Adjustment to Operation and Maintenance Expenses for Employer Insurance Benefits of AES Indiana and AES U.S. Services, LLC (AES Services) Employees
(Thousands of Dollars)

The following adjustment represents the net impact of changes to AESI and AES U.S. Services, LLC (AES Services) insurance benefit costs.

Line No.		Total Electric Per Books (Col. 1)	Pro Forma (Col. 2)	Adjustments (Col. 3)	Line No.
1	Benefit costs (AES Indiana employees)	$ 21,644	$ 23,117	$ 1,473	1
2	Benefit costs (from AES Services)	2,093	2,454	361	2
3	Net insurance benefits and AES Services costs	$ 23,737	$ 25,571		3
4	Pro forma adjustment (See Schedule OM1)			$ 1,834	4

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM16.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM17

AES Indiana
Pro Forma Adjustment to Operation and Maintenance Expenses for

Pension and OPEB Expense of AES Indiana and AES U.S. Services, LLC (AES Services) Employees
(Thousands of Dollars)

The following adjustment represents the net impact of changes to AES Indiana pension expense.

Line No.		Total Electric Per Books (Col. 1)	Pro Forma (Col. 2)	Adjustments (Col. 3)	Line No.
1	Service cost	$ 9,049	$ 5,262	$ (3,787)	1
2	Interest cost	18,305	29,881	11,576	2
3	Expected return on assets	(35,955)	(33,005)	2,950	3
4	Amortization of prior service cost	2,208	2,055	(154)	4
5	Amortization of net actuarial loss	2,079	5,486	3,407	5
6	Settlement (gain) / loss recognized	203	—	(203)	6
7	Subtotal Pension and OPEB Expense	$ (4,111)	$ 9,679	$ 13,790	7
8	Benefits claims	$ 210	$ —	$ (210)	8
9	Total Pension and OPEB Expense	$ (3,901)	$ 9,679		9
10	Pro forma adjustment (See Schedule OM1)			$ 13,580	10

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM17.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM18-S-R

AES Indiana
Pro Forma Adjustment to Operations and Maintenance Expense for the ACE Project
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment adjusts the on going O&M related to the ACE Project.

Line No.		Pro Forma ACE O&M Expense	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	ACE O&M	$ 9,322	$ 1,195	$ 8,127	1
2	Total ACE O&M	$ 9,322	$ 1,195	$ 8,127	2

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM18.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM19

AES Indiana
Pro Forma Adjustment to Remove Image-Building Advertising Costs
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects the removal of image-building advertising recorded during the test year.

Line No.		Pro Forma Image-Building Advertising Expense	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Image-building advertising in FERC Acct 930.1	$ -	$ 2,118	$ (2,118)	1
2	Image-building advertising in other accounts	—	87	(87)	2
3	Total Image-building advertising	$ -	$ 2,205	$ (2,205)	3

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM19.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM20

AES Indiana
Pro Forma Adjustment to
Injuries and Damages Expense
(Thousands of Dollars)

The following adjusts injury and damage expense to the average of the last 3 years.

Line No.		Pro Forma Costs	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Injury and Damage Expense	$ 1,599	$ 1,364	$ 235	1

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM20.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM21-S-R

AES Indiana
Pro Forma Adjustment to Amortization of Rate Case Expense
(Thousands of Dollars)

It is estimated that the following costs will be incurred in the preparation and presentation of AES Indiana's current Petition to the Commission. AES Indiana considers it reasonable to amortize these costs over three years.

Line No.		Amortization Period	Cost	Total	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Cost of depreciation and demolition studies:				1
2	Depreciation		$ 100		2
3	Demolition		180		3
4	Total projected cost of depreciation and demolition studies			$ 280	4
5	All other rate case expenses:				5
6	Legal		$ 1,900		6
7	Fair Return		75		7
8	Weather Normalization		178		8
9	Rate Design		461		9
10	Line Loss Study		80		10
11	Accounting and Tax Consulting		100		11
12	Configuration		296		12
13	Other - (e.g. Additional Witness/Consulting Support, Postage)		1,615		13
14	Total projected cost of all other rate case expenses			$ 4,705	14
15	Total pro forma cost of 2023 rate case expenses			$ 3,000	15
16	Pro forma annual amortization of rate case expenses	4 years		$ 750	16
17	Less: Per books amortization during the twelve months ended December 31, 2022			—	17
18	Total pro forma adjustment (See Schedule OM1)			$ 750	18

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM21.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM22-S-R

AES Indiana
Pro Forma Adjustments
Due to Miscellaneous Expense Items
(Thousands of Dollars)

This schedule removes items not deemed to be reasonably necessary to provide reliable electric service and also reflects

adjustments to bring certain miscellaneous test year expenses to the current experienced rate of expense as of the end of the test year.

Line No.		Pro Forma Adjustments (Col. 1)	(Col. 2)	Line No.
1	Production - Operations			1
2	Operation of Steam Power Generation	$ (44)		2
3	Maintenance of Steam Plant	(10)		3
	Other Power Production	(15)		
4			$ (69)	4
5	Transmission & Distribution			5
6	Transmission operation and maintenance expenses	$ (16)		6
7	Distribution operation and maintenance expenses	(524)		7
8			$ (540)	8
9	Customer Accounts		(3)	9
10	Customer Service & Informational		(6)	10
11	Administrative & General			11
12	Office supplies and expenses	$ (203)		12
12	Outside services employed	354		12
13	Employee Pensions and Benefits	(5)		13
14	Miscellaneous general expenses	(2,462)		14
15	Maintenance of General Plant	(7)		15
16			(2,323)	16
17	Pro forma adjustment (See Schedule OM1)		$ (2,941)	17
	Summary of pro forma adjustment			
18	Miscellaneous expense adjustments		(804)	18
19	Run-rate adjustment		(2,137)	19
20	Total pro forma adjustment (agrees to line 17 above)		$ (2,941)	20

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM22.

AES Indiana
Pro Forma Adjustment to
AES U.S. Services, LLC (AES Services) Occupancy and Non-Labor Costs
(Thousands of Dollars)

Line No.		Occupancy Revenue (Col. 1)	Occupancy Charges (Col. 2)	Non-labor Expenses (Col. 3)	Total (Col. 4)	Line No.
	Pro forma:					
1	Costs allocated to AES Indiana from AES Services		$ 3,074	$ 73		1
2	Revenue charged to AES Services by AES Indiana	$ (7,002)				2
3	Totals	(7,002)	3,074	73	$ (3,855)	3
	Per books for the twelve months ended December 31, 2022:					
4	Costs allocated to AES Indiana from AES Services		$ 2,714	$ 58		4
5	Revenue charged to AES Services by AES Indiana	$ (5,771)				5
6	Totals	(5,771)	2,714	58	$ (3,000)	6
7	Net pro forma adjustments	$ (1,231)	$ 361	$ 14		7
8	Pro forma adjustment (See Schedule OM1)				$ (855)	8

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM23.

AES Indiana
Remove Items Recovered via Trackers Which Have Not Already Been Eliminated via other Pro Forma Adjustments
(Thousands of Dollars)

The following pro forma adjustment removes ECR and TDSIC tracker related items that have not been removed via other pro forma adjustments. Because these items are fully recovered via a tracker, they should not be included in basic rates.

Line No.		Pro Forma Adjustment (See Schedule OM1) (Col. 1)	Line No.
1	Remove AMI Opt Out Cost Amortization which was recovered via the ECR Tracker- FERC 923	$ (156)	1
2	Remove TDSIC Program Development Costs Amortization which was recovered via the TDSIC Tracker- FERC 923	(784)	2
3	Remove TDSIC Tracker Variance and Amortization recovered via the TDSIC tracker recorded to FERC 923 (1)	18	3
4	Pro forma adjustment to eliminate ECR, TDSIC tracker items (See Schedule OM1)	$ (922)	4

(1) The monthly TDSIC tracker variance is recorded to FERC accounts 408100 (property taxes), 407300/400 (regulatory credits and debits), and 923 (outside services). The amounts recorded to FERC accounts 408100 and 407300/400 were removed from the test year via the DEPR exhibit and the OTX2 exhibit.

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM24.

AES Indiana Financial Exhibit AESI-OPER
AES Indiana 2023 Basic Rates Case
Schedule OM25

AES Indiana
Pro Forma Adjustment to
Property and Other Casualty Insurance Expense
(Thousands of Dollars)

The following adjustments represent the net impact of changes to AES Indiana's property insurance premiums due to rate changes.

Line No.		Pro Forma Costs	Twelve Months Ended 12/31/2022 Per Books	Pro Forma Adjustment (See Schedule OM1)	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	
1	Property and Other Casualty Insurance	$ 19,125	$ 14,260	$ 4,864	1

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM25.

AES Indiana 2023 Basic Rates Case

AES Indiana Attachment CAR-2S
Schedule OM26

AES Indiana
Pro Forma Adjustment to
Write-Off of Preliminary Survey and Investigation Charges and Cancelled Capital Projects
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

The following pro forma adjustment reflects a normalization of write-offs from FERC 183.1 Other Preliminary Survey and Investigation Charges and cancelled capital projects.

Line No.	Description	Amount (Col. 1)	Line No.
1	Actual write off for the 12 month period ended December 31, 2020	$ 2,192	1
2	Actual write off for the 12 month period ended December 31, 2021	168	2
3	Actual write off for the 12 month period ended December 31, 2022	1,668	3
4	Total write off for the 3 year period ended December 31, 2022	$ 4,028	4
5	3-year average write off of other preliminary survey and investigation charges and cancelled capital projects	$ 1,343	5
6	Per books write-offs during the twelve months ended December 31, 2022	1,668	6
7	Pro forma adjustment (See Schedule OM1)	$ (325)	7

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM26.

AES Indiana
Pro Forma Adjustments to Uncollectible Accounts Expense
(Thousands of Dollars)

The following adjustments reflect the application of the experience rate of uncollectible accounts to the respective pro forma electric revenues.

Line No.		Total Electric At Present Rates (Col. 1)	Total Electric At Proposed Rates (Col. 2)	Supporting AES Indiana Financial Exhibit Reference (Col. 3)	Line No.
1	Electric operating revenues for the twelve months ended December 31, 2022	$ 1,571,599	$ 1,642,636	AESI-OPER, Sch. OPINC, Line 1, Cols. 4 and 6	1
2	Less: Off-system sales	28,612	28,612	AESI-OPER, Sch. REV1, Line 6, Cols. 3 and 5	2
3	Less: Rents from electric property	3,238	3,238	AESI-OPER, Sch. REV1, Line 9, Cols. 3 and 5	3
4	Less: Capacity sales	—	—	AESI-OPER, Sch. REV1, Line 7, Cols. 3 and 5	4
5	Less: Miscellaneous electric revenue	5,297	5,297	AESI-OPER, Sch. REV1, Line 11, Cols. 3 and 5	5
6	Net	$ 1,534,452	$ 1,605,489		6
7	Uncollectible accounts experience rate	0.3814 %			7
8	Pro forma uncollectible electric accounts expense	$ 5,852	$ 6,123		8
9	Amount charged to total electric operating expense for the twelve months ended December 31, 2022	7,478			9
10	Pro forma adjustment at present rates	$ (1,626)		(See Exhibit AESI-OPER, Sch. OM1, Column 1)	10
11	Less: Pro forma electric at present rates expense		5,852		11
12	Pro forma adjustment at proposed rates		$ 271	(See Exhibit AESI-OPER, Sch. OM1, Column 2)	12

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM27.

AES Indiana
Pro Forma Adjustments to Public Utility Fee
(Thousands of Dollars)

The following adjustments reflect the application of the public utility fee, increased by the current billing factor, to the respective pro forma electric revenues.

Line No.	Description	Total Electric At Present Rates (Col. 1)	Total Electric At Proposed Rates (Col. 2)	Supporting AES Indiana Financial Exhibit Reference (Col. 3)	Line No.
1	Electric operating revenues for the twelve months ended December 31, 2022	$ 1,571,599	$ 1,642,636	AESI-OPER, Sch. OPINC, Line 1, Cols. 4 and 6	1
2	Less : Capacity Sales	(11,750)	(11,750)	AESI-OPER, Sch. REV1, Line 7, Cols. 3 and 5	2
3	Less: Off-system sales	28,612	28,612	AESI-OPER, Sch. REV1, Line 6, Cols. 3 and 5	3
4	Less: Rents	3,238	3,238	AESI-OPER, Sch. REV1, Line 9, Cols. 3 and 5	4
5	Less: Other customer charges	16,875	16,875	AESI-OPER, Sch. REV1, Line 10, Cols. 3 and 5	5
6	Less: Miscellaneous electric revenues	5,297	5,297	AESI-OPER, Sch. REV1, Line 11, Cols. 3 and 5	6
7	Less: Uncollectible accounts expense	5,852	6,123	AESI-OPER, Sch. OM27, Line 8, Cols. 1 and 2	7
8	Net electric operating revenue subject to public utility fee	$ 1,523,475	$ 1,594,241		8
9	Effective public utility fee rate	0.001468			9
10	Pro forma public utility fee	$ 2,236	$ 2,341		10
11	Fee charged to total electric operating expense during the twelve months ended December 31, 2022	1,608			11
12	Pro forma adjustment at present rates	$ 628		(See Exhibit AESI-OPER, Sch. OM1, Column 1)	12
13	Less: Pro forma electric at present rates expense		2,236		13
14	Pro forma adjustment at proposed rates		$ 105	(See Exhibit AESI-OPER, Sch. OM1, Column 2)	14

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OM28-S-R

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OM28.

AES Indiana
Pro Forma Adjustment to Total Electric at Present Rates to Reflect the Annual Provision for Depreciation and Amortization Expense for the Twelve Month Period Ended December 31, 2022
Applying Proposed Depreciation and Amortization Rates to Pro Forma Original Cost Rate Base
(Thousands of Dollars)

Line No.		Functional Classification Intangible Plant (Col. 1)	Systems Software (Col. 2)	Production Plant (Col. 3)	Transmission Plant (Col. 4)	Distribution Plant (Col. 5)	General Plant (Col. 6)	Total (Col. 7)	Line No.
1	Total electric utility plant in service per books (1)	$ 46	$ 153,606	$ 4,166,085	$ 461,042	$ 2,036,697	$ 260,172	$ 7,077,849	1
2	Less: Asset retirement obligation asset (2)			(195,718)	(30)	(235)	(693)	(196,676)	2
3	Less: Fully depreciated utility plant		(78,784)	(4,710)				(83,494)	3
4	Less: Non-depreciable assets included above - land and other	(46)		(3,672)	(546)	(3,621)	(3,775)	(11,660)	4
5	Total depreciable assets in service per books at December 31, 2022	$ —	$ 74,822	$ 3,961,985	$ 460,466	$ 2,032,841	$ 255,705	6,785,819	5
6	Less: Non-jurisdictional plant-in-service (3)				$ (20,788)			(20,788)	6
7	Add: ACE Project (4)		$ 83,838					83,838	7
8	Less: Pete Unit 2 and 1&2 Shared Asset Retirements (5)			$ (501,630)				(501,630)	8
9	Less: EV CCGT Forced Outage (5)			$ (11,112)				(11,112)	9
10	Total depreciable assets	$ —	$ 158,660	$ 3,449,242	$ 439,678	$ 2,032,841	$ 255,705	6,336,126	10
11	Pro forma depreciation and amortization	$ —	$ 19,225	$ 192,067	$ 9,162	$ 36,790	$ 12,732	269,976	11
12	Add: Plant acquisition adjustment amortization (6)							15	12
13	Add: Amortization of regulatory assets on AESI-RB, Schedule RB9 (7)							31,505	13
14	Total pro forma depreciation and amortization expense							$ 301,496	14
15	Less: regulatory asset amortization charges to FERC 923 for the twelve months ended December 31, 2022.							91	15
16	Less: Total depreciation and amortization expense charged to depreciation and amortization expense for the twelve months ended December 31, 2022 (8)							272,093	16
17	Pro forma adjustment (See AESI-OPER, Schedule OPINC, Line 3, Column 3)							$ 29,312	17

(1) See AESI-RB, Schedule RB2, Line 9
(2) See AESI-RB, Schedule RB6, Line 7
(3) See AESI-RB, Schedule RB5, Line 7
(4) See AESI-RB, Schedule RB3, Line 3
(5) See AESI-RB, Schedule RB4, Line 9
(6) Reflects a 33-year amortization period, the estimated remaining useful life of the asset at the time of the acquisition.
(7) See AESI-RB, Schedule RB9 Page 4 of 5, Line 32
(8) See AESI-OPER, Schedule OPINC, Line 3, Column 2

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper DEPR.

AES Indiana
Summary of Taxes Other than Income Taxes for the Twelve Months Ended December 31, 2022
Per Books and Pro Forma at Present and Proposed Rates
(Thousands of Dollars)

Line No.		Adjustment Shown on AESI Financial Exhibit AESI-OPER (Col. 1)	Total Electric Per Books (Col. 2)	Total Electric At Present Rates Adjustments (Col. 3)	Pro Forma (Col. 4)	Total Electric At Proposed Rates Adjustments (Col. 5)	Pro Forma (Col. 6)	Line No.
1	Real estate and personal property taxes	Sch. OTX2	$ 12,620	$ 3,369	$ 15,989	$ —	$ 15,989	1
2	Payroll taxes	Sch. OTX3	9,014	1,257	10,272	—	10,272	2
3	Indiana utility receipts tax	Sch. OTX4	11,096	(11,096)	—	—	—	3
4	Miscellaneous taxes		733	—	733	—	733	4
5	Total taxes other than income taxes (See AESI Financial Exhibit AESI-OPER, Schedule OPINC, Line 4)		$ 33,464	$ (6,470)	$ 26,994	$ —	$ 26,994	5

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OTX1.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OTX2

AES Indiana
Pro Forma Adjustment to
Real Estate and Personal Property Taxes, Including Rail Car Tax
For the Twelve Months Ended December 31, 2022
(Thousands of Dollars, Except Composite Property Tax Rate)

Line No			(Col. 1)	Line No
1	Pro forma assessed valuation as of 12/31/2022 (Excluding Rail Cars)		$ 736,311	1
2	Composite net property tax rate per $100 of assessed valuation		2.2248	2
3	Pro forma real estate and personal property tax		$ 16,381	3
4		Add: Addition for Rail Car Tax	60	4
5	Total pro forma real estate and personal property taxes, including rail car tax chargeable to electric operating income, prior to retirement of Pete Unit 2		$ 16,442	5
6		Less, Per books real estate and personal property taxes expense	12,620	6
7	Pro forma adjustment to real estate and personal property taxes including Rail Car tax chargeable to electric operating income, prior to retirement of Pete Unit 2		3,822	7
8	Pro forma adjustment to real estate and personal property taxes for Pete Unit 2 retired May 31, 2023		(453)	8
9	Total pro forma adjustment to real estate and personal property taxes, including Rail Car tax, chargeable to electric operating income (See Schedule OTX1, Line 1, Col. 3)		$ 3,369	9

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OTX2.

AES Indiana
Pro Forma Adjustment to Reflect the Change in
Payroll Taxes Applicable to Pro Forma Wage Adjustments and Changes in Tax Rates
Chargeable to Operation and Maintenance Expense
(Thousands of Dollars)

The following adjustment represents the net impact of changes to AESI and AES U.S. Services, LLC (AES Services) payroll tax costs

Line No.		Total Electric Per Books (Col. 1)	Pro Forma (Col. 2)	Adjustments (Col. 3)	Line No.
1	Payroll Tax costs (AESI employees)	$ 7,621	$ 8,664	$ 1,043	1
2	Payroll Tax costs (from AES Services)	1,394	1,608	214	2
3	Total Payroll Tax, AESI and AES Services costs	$ 9,014	$ 10,272		3
4	Pro forma adjustment (See Schedule OM1)			$ 1,257	4

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OTX3.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule OTX4

AES Indiana
Pro Forma Adjustment To Indiana Utility Receipts Tax (URT) at Present and Proposed Rates
(Thousands of Dollars)

Line No.		Total Electric Per Books at 12/31/2022 (Col. 1)	Pro Forma Adjustment At Present Rates (Col. 2)	Pro Forma Adjustment At Proposed Rates (Col. 3)	Line No.
1	URT taxable income for the twelve months ended December 31, 2022:				1
2	URT 01 Retail Sales of Utility Services - Operating	$ 761,327			2
3	URT 05 Electric rent revenue	3,698			3
4	URT 06 Other Receipts	9,047			4
5	URT 08 Exemptions	(1)			5
6	URT 09 Bad Debt	(3,249)			6
7	URT 10 Depreciation on Resource Recovery Systems	(6,488)			7
8	Net	$ 764,335			8
9	URT tax rate	1.46 %			9
10	URT tax	$ 11,159			10
11	URT for the twelve months ended December 31, 2022 per books	$ 11,096	$ (11,096)		11
12	Remove URT out-of-period adjustment	63			12
13	Net URT per books	$ 11,159			13
14	Net pro forma adjustment at present rates (See Schedule OTX1, Col. 3, Line 3)		$ (11,096)		14
15	Total pro forma adjustment at proposed rates (See Schedule OTX1, Col. 5, Line 3)			$ —	15

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper OTX4.

AES Indiana

Summary of Income Taxes for the Twelve Months Ended December 31, 2022
Per Books and Pro Forma at Present and Proposed Rates
(Thousands of Dollars)

Line No.		Adjustment Shown on AES Indiana Financial Exhibit	Total Electric Per Books	Total Electric At Present Rates		Total Electric At Proposed Rates		Line No.
				Adjustments	Pro Forma	Adjustments	Pro Forma	
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	
1	Current - federal (See Schedule OPINC, Line 7)	Schedule TX2	$ 31,385	$ (334)	$ 31,051	$ 14,112	$ 45,163	1
2	Current - state (See Schedule OPINC, Line 8)	Schedule TX3	8,168	(658)	7,510	3,462	10,972	2
3	Deferred - federal (See Schedule OPINC, Line 9)	Schedule TX4	(7,278)	(4,241)	(11,519)	—	(11,519)	3
4	Deferred - state (See Schedule OPINC Line 10)	Schedule TX4	125	(1,985)	(1,860)	—	(1,860)	4
5	Investment tax credit adjustments (See Schedule OPINC, Line 11)	Schedule TX5	(3)	—	(3)	—	(3)	5
6	Total income taxes (See Schedule OPINC, Line 12)		$ 32,397	$ (7,218)	$ 25,179	$ 17,574	$ 42,753	6

AES Indiana
Pro Forma Adjustment to the Computation of Current Federal Income Tax Expense at Present Rates and at Proposed Rates
(Thousands of Dollars)

Line No.		Per Books at 12/31/2022 (Col. 1)	Pro Forma Adjustments at Present Rates (Col. 2)	Pro Forma Federal Income Tax at Present Rates (Col. 3)	Pro Forma Adjustments at Proposed Rates (Col. 4)	Pro Forma Federal Income Tax at Proposed Rates (Col. 5)	Line No.
1	Operating revenues (1)	$ 1,791,546	$ (219,947)	$ 1,571,599	$ 71,037	$ 1,642,636	1
	Less:						
2	Operation and maintenance expenses (1)	1,242,330	(207,195)	1,035,135	376	1,035,511	2
3	Depreciation and amortization expense (1)	272,093	29,312	301,405	—	301,405	3
4	Taxes other than income taxes (1)	33,464	(6,470)	26,994	—	26,994	4
5	Operating income before income taxes (1)	243,660	(35,595)	208,065	70,661	278,726	5
	Permanent book/tax differences:						
6	Disallowed parking	558	—	558	—	558	6
7	Meals & entertainment	808	(362)	446	—	446	7
8	Other	(13)	13	—	—	—	8
9	Total permanent	1,352	(348)	1,004	—	1,004	9
	Temporary book/tax differences:						
10	Pension	(3,643)	13,733	10,090	—	10,090	10
11	Insurance reserve	71	—	71	—	71	11
12	NOx	174	—	174	—	174	12
13	Contingent liabilities	125	—	125	—	125	13
14	MISO	14,896	—	14,896	—	14,896	14
15	MPP	134	(41)	93	—	93	15
16	Reserve for uncollectible accounts	(150)	—	(150)	—	(150)	16
17	Accrued property tax	—	—	—	—	—	17
18	Early retirement of debt	1,274	—	1,274	—	1,274	18
19	Supplemental pension	(158)	(161)	(319)	—	(319)	19

AES Indiana
Pro Forma Adjustment to the Computation of Current Federal Income Tax Expense at Present Rates and at Proposed Rates
(Thousands of Dollars)

Line No.		Per Books at 12/31/2022 (Col. 1)	Pro Forma Adjustments at Present Rates (Col. 2)	Pro Forma Federal Income Tax at Present Rates (Col. 3)	Pro Forma Adjustments at Proposed Rates (Col. 4)	Pro Forma Federal Income Tax at Proposed Rates (Col. 5)	Line No.
	(Continued from Page 1)						
20	Accrued vacation	$ 202	$ —	$ 202	$ —	$ 202	20
21	Post-retirement benefits	(874)	218	(656)	—	(656)	21
22	Long term compensation	257	(77)	180	—	180	22
23	Performance bonus	(351)	2,513	2,163	—	2,163	23
24	Rate case expenses	(230)	980	750	—	750	24
25	Electric vehicle sup equip	106	—	106	—	106	25
26	NAAQS	25	45	70	—	70	26
27	Accrued severance	262	(417)	(155)	—	(155)	27
28	MATS	872	226	1,098	—	1,098	28
29	NPDES	29	471	500	—	500	29
30	CCGT/Harding Street 5&6	1,482	173	1,656	—	1,656	30
31	Major storm damage	1,363	—	1,363	—	1,363	31
32	Capacity cost recovery	(33)	—	(33)	—	(33)	32
33	Harding Street 7	568	(650)	(83)	—	(83)	33
34	Petersburg Unit No. 4 regulatory amortization	1,054	(0)	1,054	—	1,054	34
35	Payroll tax	(2,652)	2,652	—	—	—	35
36	Pete 1	12,605	(7,605)	5,000	—	5,000	36
37	Pete 2 & Pete 1 & 2 Shared	—	11,572	11,572	—	11,572	37
38	TDSIC	(5,441)	5,764	323	—	323	38
39	AMI	162	—	162	—	162	39
40	Deferred fuel	4,336	—	4,336	—	4,336	40
41	Hardy Hills	(1,910)	—	(1,910)	—	(1,910)	41
42	COVID-19	—	1,357	1,357	—	1,357	42
43	451 method change	8,239	—	8,239	—	8,239	43
44	Research & experimental expenditures	1,235	(7,993)	(6,759)	—	(6,759)	44

AES Indiana
Pro Forma Adjustment to the Computation of Current Federal Income Tax Expense at Present Rates and at Proposed Rates
(Thousands of Dollars)

Line No.		Per Books at 12/31/2022	Pro Forma Adjustments at Present Rates	Pro Forma Federal Income Tax at Present Rates	Pro Forma Adjustments at Proposed Rates	Pro Forma Federal Income Tax at Proposed Rates	Line No.
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	
	(Continued from Page 2)						
45	AFUDC debt	$ (8,215)	$ —	$ (8,215)	$ —	$ (8,215)	45
46	Capitalized interest	4,081	—	4,081	—	4,081	46
47	CIAC	16,726	—	16,726	—	16,726	47
48	Tax depreciation (net of capitalized depr.)	(213,244)	22,378	(190,867)	—	(190,867)	48
49	Tax gain/loss & removal costs	(23,450)	—	(23,450)	—	(23,450)	49
50	Book depreciation	263,798	6,193	269,991	—	269,991	50
51	Mixed service costs	(4,219)	—	(4,219)	—	(4,219)	51
52	Repairs	(70,841)	—	(70,841)	—	(70,841)	52
53	Total temporary	(1,334)	51,331	49,997	—	49,997	53
	Interest						
54	Less: Actual / synchronized interest (2)	86,682	(3,661)	83,022	—	83,022	54
55	Less: Parent interest (3)		20,672	20,672	—	20,672	55
56	Adjusted operating income before income taxes	156,995	(1,623)	155,372	70,661	226,033	56
57	Less: State net income tax expense (4)	8,133	(623)	7,510	3,462	10,972	57
58	Add: Net operating loss adjustment (non-recurring)	—	—	—	—	—	58
59	Taxable federal net income	$ 148,862	$ (1,000)	$ 147,862	$ 67,199	$ 215,061	59
60	Federal income tax rate	21.0 %					60
61	Federal income tax expense @ 21%	$ 31,261	$ (210)	$ 31,051	$ 14,112	$ 45,163	61

AES Indiana
Pro Forma Adjustment to the Computation of Current Federal Income Tax Expense at Present Rates and at Proposed Rates
(Thousands of Dollars)

Line No.		Per Books at 12/31/2022 (Col. 1)	Pro Forma Adjustments at Present Rates (Col. 2)	Pro Forma Federal Income Tax at Present Rates (Col. 3)	Pro Forma Adjustments at Proposed Rates (Col. 4)	Pro Forma Federal Income Tax at Proposed Rates (Col. 5)	Line No.
	(Continued from Page 3)						
62	Amount recorded on books for the twelve months ended December 31, 2022	$ 31,385					62
	Out-of-period adjustments:						
63	Remove 2021 tax return adjustments	(124)	(124)				63
64	Adjusted per books net federal income taxes for the twelve months ended December 31, 2022	$ 31,261					64
65	Net pro forma adjustment at present rates (See Schedule TX1, Line 1, Column 3)		$ (334)				65
66	Pro forma federal income tax at present rates			$ 31,051			66
67	Pro forma adjustment at proposed rates (See Schedule TX1, Line 1, Column 5)				$ 14,112		67
68	Pro forma federal income tax at proposed rates					$ 45,163	68

(1) See AESI-OPER, Schedule OPINC
(2) See AESI-OPER, Schedule TX6
(3) See AESI-OPER, Schedule TX7
(4) See AESI-OPER, Schedule TX3

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper TX2.

AES Indiana
Pro Forma Adjustment to the Computation of Current State Income Tax Expense at Present Rates and at Proposed Rates
(Thousands of Dollars)

Line No.		Per Books at 12/31/2022 (Col. 1)	Pro Forma Adjustments at Present Rates (Col. 2)	Pro Forma State Income Tax at Present Rates (Col. 3)	Pro Forma Adjustments at Proposed Rates (Col. 4)	Pro Forma State Income Tax at Proposed Rates (Col. 5)	Line No.
1	Federal taxable operating income before income taxes	$ 156,995	$ (1,623)	$ 155,372	$ 70,661	$ 226,033	1
2	Add: Utility receipts tax (see Schedule OTX4)	11,096	(11,096)	—	—	—	2
3	Charitable contributions	—	—	—	—	—	3
4	Less: U.S. interest	—	—	—	—	—	4
5	Bonus depreciation adjustment	2,118	—	2,118	—	2,118	5
6	State net taxable income (before adjustments)	165,974	(12,719)	153,255	70,661	223,916	6
7	Add: Net operating loss adjustment (non-recurring)	—	—	—	—	—	7
8	State net taxable income	$ 165,974	$ (12,719)	$ 153,255	$ 70,661	$ 223,916	8
9	State income tax rate (blended as needed)	4.9000 %	4.9000 %	4.9000 %	4.9000 %	4.9000 %	9
10	State net income tax expense	$ 8,133	$ (623)	$ 7,509	$ 3,462	$ 10,972	10
11	Amount recorded on books for the twelve months ended December 31, 2022	$ 8,168					11
12	Out-of-Period: Remove 2021 tax return adjustments	(35)	(35)				12
13	Adjusted state income taxes per books for the twelve months ended December 31, 2022	$ 8,133					13
14	Net pro forma adjustment at present rates (See Schedule TX1, Line 2, Column 3)		$ (658)				14
15	Pro forma state income tax at present rates			$ 7,510			15
16	Net pro forma adjustment at proposed rates (See Schedule TX1, Line 2, Column 5)				$ 3,462		16
17	Pro forma state income tax at proposed rates					$ 10,972	17

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper TX3.

AES Indiana

Pro Forma Adjustment to Federal and State Deferred Income Tax Expense at Present Rates and at Proposed Rates for the Twelve Months Ended December 31, 2022

(Thousands of Dollars)

Calculations are based on pro forma electric utility plant in service at December 31, 2022, and reflect scheduled differences and their associated deferred taxes, as determined by AESI's application of comprehensive inter-period tax allocation and normalization principles.

Line No.		Federal Electric Deferred Income Tax Per Books (Col.1)	State Electric Deferred Income Tax Per Books (Col. 2)	Total Electric Deferred Income Tax Per Books (Col. 3)	Federal Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 4)	State Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 5)	Total Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 6)	Line No.
1	Pension	$ 728	$ 179	$ 906	$ (2,743)	$ (673)	$ (3,415)	1
2	Insurance reserve	(14)	(3)	(18)	—	—	—	2
3	NOx	(35)	(9)	(43)	—	—	—	3
4	Contingent liabilities	(99)	(24)	(123)	—	—	—	4
5	MISO	(2,975)	(730)	(3,705)	—	—	—	5
6	MPP	(27)	(7)	(33)	8	2	10	6
7	Union lump sum	(10)	(2)	(12)	—	—	—	7
8	Reserve for uncollectible accounts	30	7	37	—	—	—	8
9	Accrued property tax	131	32	164	—	—	—	9
10	Early retirement of debt	(252)	(62)	(314)	—	—	—	10
11	Supplemental pension	32	8	39	32	8	40	11
12	Accrued vacation	(40)	(10)	(50)	—	—	—	12
13	Post-retirement benefits	175	43	217	(44)	(11)	(54)	13
14	Long term compensation	132	32	165	15	4	19	14
15	Performance bonus	70	17	87	(502)	(123)	(625)	15
16	Rate case expenses	46	11	57	(196)	(48)	(244)	16
17	Electric vehicle sup equip	(21)	(5)	(26)	—	—	—	17
18	NAAQS	(5)	(1)	(6)	(9)	(2)	(11)	18
19	Accrued severance	(67)	(16)	(83)	83	20	104	19
20	MATS	(174)	(43)	(217)	(45)	(11)	(56)	20
21	NPDES	(6)	(1)	(7)	(94)	(23)	(117)	21
22	CCGT/Harding Street 5&6	(296)	(73)	(369)	(35)	(8)	(43)	22
23	Major storm damage	(272)	(67)	(339)	—	—	—	23
24	Capacity cost recovery	6	2	8	—	—	—	24
25	Harding Street 7	(113)	(28)	(141)	130	32	162	25
26	Research & experimental expenditures	(247)	(60)	(307)	1,596	392	1,988	26
27	Payroll tax	530	130	659	(530)	(130)	(659)	27

AES Indiana
Pro Forma Adjustment to Federal and State Deferred Income Tax Expense at Present Rates and at Proposed Rates for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.		Federal Electric Deferred Income Tax Per Books (Col.1)	State Electric Deferred Income Tax Per Books (Col. 2)	Total Electric Deferred Income Tax Per Books (Col. 3)	Federal Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 4)	State Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 5)	Total Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 6)	Line No.
	(Continued from Page 1)							
28	Pete 1	$ (2,517)	$ (618)	$ (3,135)	$ 1,519	$ 373	$ 1,891	28
29	Pete 2 & Pete 1 & 2 Shared	—	—	—	(2,311)	(567)	(2,878)	29
30	TDSIC	1,087	267	1,353	(1,151)	(282)	(1,434)	30
31	AMI	(32)	(8)	(40)	—	—	—	31
32	Deferred fuel	(866)	(212)	(1,078)	—	—	—	32
33	Hardy Hills	381	94	475	—	—	—	33
34	COVID-19	—	—	—	(271)	(66)	(337)	34
35	451 method change	(1,645)	(404)	(2,049)	—	—	—	35
36	Petersburg Unit No. 4 regulatory amortization	(220)	(25)	(245)	0	0	0	36
37	AFUDC debt	1,643	391	2,034	—	—	—	37
38	Capitalized interest	(818)	(184)	(1,002)	—	—	—	38
39	CIAC	(3,338)	(833)	(4,171)	—	—	—	39
40	Tax depreciation (net of capitalized depr.)	42,262	9,988	52,250	(4,469)	(1,097)	(5,566)	40
41	Tax gain/loss & removal costs	4,683	1,149	5,832	—	—	—	41
42	Book depreciation	(50,852)	(12,477)	(63,329)	(1,237)	(303)	(1,540)	42
43	Mixed service costs	842	207	1,049	—	—	—	43
44	Repairs	14,148	3,471	17,619	—	—	—	44
45	Excess ADIT Amortization	(9,262)	—	(9,262)	5,909	—	5,909	45
46	Total pro forma adjustments at present rates				(4,342)	(2,515)	(6,857)	46
47	Deferred tax expense per books recorded for the twelve months ended December 31, 2022	(7,278)	125	(7,152)				47
	Out-of-period adjustments:							
48	Remove 2022 adjustment for IN rate change	—	441	441	—	441	441	48
49	Remove 2021 tax return adjustments	101	89	190	101	89	190	49

AES Indiana
Pro Forma Adjustment to Federal and State Deferred Income Tax Expense
at Present Rates and at Proposed Rates for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.		Federal Electric Deferred Income Tax Per Books (Col.1)	State Electric Deferred Income Tax Per Books (Col. 2)	Total Electric Deferred Income Tax Per Books (Col. 3)	Federal Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 4)	State Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 5)	Total Electric Deferred Tax Adjustment Pro Forma at Present Rates (Col. 6)	Line No.
50	Adjusted deferred tax expense for the twelve months ended December 31, 2022	$ (7,177)	$ 655	$ (6,522)				50
	(Continued from Page 2)							
51	Total pro forma adjustments to deferred federal and state income tax expense at present rates							
	(See Schedule TX1, Column 3, Lines 3 and 4, respectively)				$ (4,241)	$ (1,985)	$ (6,226)	51
52	Net operating loss adjustment at proposed rates				$ —	$ —	$ —	52
53	Total pro forma adjustments to deferred federal and state income tax expense at proposed rates							
	(See Schedule TX1, Column 5, Lines 3 and 4, respectively)				$ —	$ —	$ —	53

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper TX4.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule TX5

AES Indiana
Pro Forma Adjustment to Investment Tax Credit (ITC) Expense
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.		Pro Forma Electric ITC at Present Rates (Col. 1)	Total Electric ITC for the Twelve Months Ended 12/31/2022 (Col. 2)	Pro Forma Adjustment at Present Rates (Col. 3)	Line No.
1	Total electric amortization of credit	$ (3)	$ (3)	$ —	1
2	Pro forma adjustment (See Schedule TX1, Line 5, Column 3)			$ —	2

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper TX5.

AES Indiana
Determination of Interest Expense for Interest Synchronization
(Thousands of Dollars)

Line No.		Total Company Capitalization (Col. 1)		Percent of Total (Col. 2)	Cost (Col. 3)		Total Weighted Cost (Col. 4)	Original Cost Total Electric Rate Base (Col. 5)		Total Electric Synchronized Interest (Col. 6)	Line No.
1	Long-Term Debt	$ 2,153,036	(1)	49.15 %	4.90 %	(1)	2.41 %	$ 3,444,878	(3)	$ 83,022	1
2	Preferred Equity	—		— %							2
3	Common Equity	1,943,109	(2)	44.36 %							3
4	Prepaid Pension Asset (net of OPEB liability)	(133,100)	(2)	(3.04)%							4
5	Deferred Income Taxes	382,560	(2)	8.73 %							5
6	Post 1970 ITC	24	(2)	0.00 %							6
7	Customer Deposits	35,097	(2)	0.80 %							7
8		$ 4,380,726		100.00 %						$ 83,022	8

(1) See AESI-CC, Schedule CC1
(2) See AESI-CC, Schedule CC2
(3) See AESI-RB, Schedule RB1, Column 6, Line 9

AES Indiana
Imputation of Parent Company Interest
(Thousands of Dollars)

Line No.	Description	AESI Pro Forma Equity Capital (Col. 1)	AES Corp. Parent Debt Ratio (From Line 5, Col. 5) (Col. 2)	AESI Equity Represented by Parent Debt (Col. 3)	AES Corp Average Interest Rate (From Line 24, Col. 5) (Col. 4)	Deduction For Parent Debt (Col. 5)	Line No.
1	Common stock	$ 324,537	46.57 %	$ 151,122	3.14 %	$ 4,750	1
2	Paid in capital (1)	662,428	46.57 %	308,463	3.14 %	9,695	2
3	Retained earnings	425,466	46.57 %	198,120	3.14 %	6,227	3
4		$ 1,412,431		$ 657,705		$ 20,672	4

AES Corporation
Capital Structure and Long-Term Debt as of December 31, 2022

Line No.	Capital Structure	Amount	Ratio	Line No.
5	Long-term debt	$ 3,925,000	46.57 %	5
6	Preferred stock	838,000	9.94 %	6
7	Common stock	8,000	0.09 %	7
8	Paid in capital	6,688,000	79.35 %	8
9	Retained earnings	(1,635,000)	(19.40)%	9
10	Accumulated other comprehensive loss	(1,640,000)	(19.46)%	10
11	Treasury stock	(1,822,000)	(21.62)%	11
12	Non-controlling interest equity	2,067,000	24.52 %	12
13	Total	$ 8,429,000	100.00 %	13

(1) Excludes capital contributions from CDPQ ($530,679).

AES Indiana
Imputation of Parent Company Interest
(Thousands of Dollars)

	Long-Term Debt Description	Interest Rate	Amount	Annual Cost	
14	Senior Variable Rate Term Loan due 2024	5.425 %	200,000	10,850	14
15	Senior Unsecured Notes due 2025	3.300 %	900,000	29,700	15
16	Drawings on revolving credit facility due 2027	6.050 %	325,000	19,663	16
17	Senior Unsecured Notes due 2026	1.375 %	800,000	11,000	17
18	Senior Unsecured Notes due March 2030	3.95 %	700,000	27,650	18
19	Senior Unsecured Notes due April 2031	2.45 %	1,000,000	24,500	19
20	Total - AES Corporation Long-Term Debt		$ 3,925,000	$ 123,363	20
21	Average Net Cost			3.14 %	21

Note: The Excel version of this exhibit and supporting workpapers has been filed as AES Indiana Workpaper TX7.

AES Indiana 2023 Basic Rates Case
AES Indiana Attachment CAR-2S
Schedule TX8-S-R

AES Indiana
Calculation of Effective Income Tax Rate
for the Twelve Months Ended December 31, 2022
(Thousands of Dollars)

Line No.			Pro Forma at Present Rates	Line No.
	Income Taxes (1)			
1	Current federal-operations	$	31,051	1
2	Deferred federal-operations		(11,519)	2
3	ITC-credit (amortization)		(3)	3
4	**Federal Taxes**		19,529	4
5	Current state-operations		7,510	5
6	Deferred state-operations		(1,860)	6
7	**State Taxes**		5,650	7
8	Total Income taxes	$	25,179	8
9	Net operating income before income taxes (2)	$	208,065	9
10	Less: Synchronized interest (3)		83,022	10
11	Adjusted income before income taxes	$	125,043	11
12	Federal Effective Income Tax Rate (line 4 divided by line 11)		15.62 %	12
13	State Effective Income Tax Rate (line 7 divided by line 11)		4.52 %	13
14	**Total Effective Income Tax Rate**		20.14 %	14

(1) See Exhibit AESI-OPER, Schedule TX1
(2) See Exhibit AESI-OPER, Schedule OPINC, Column 4, Line 6
(3) See Exhibit AESI-OPER, Schedule TX6, Column 6, Line 8

AES Indiana
Comparison of Current and Settlement Revenues

				Nov 22 - Settlement					ACE Capital Update					
Line No.	Rate Class	Rate Code	Current Revenue [1]	Unmitigated Nov 22 Settlement Revenue [1]	Mitigated Nov 22 Settlement Revenue [1]	Increase: Unmitigated - Current	Increase: Mitigated [2]	Increase: Mitigated (%)	Proportion of Nov 22 Settlement Revenue by Rate Class (%)	ACE Capital Update	Allocation of ACE Capital Update Reduction	Final Mitigated Revenue Requirement	Final Increase ($)	Final Increase (%)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
1	Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 656.800.000	$ 745.657.407	$ 706.107.213	$ 88.857.407	$ 49.307.213	7.51%	44.31%		$ (832.701)	$ 705.274.511	$ 48.474.511	**7.38%**
2	Secondary Service (Small) (Rate SS)	SS	174.117.141	157.625.523	178.064.882	(16.491.619)	3.947.741	2.27%	11.17%		$ (209.989)	177.854.893	3.737.752	**2.15%**
3	Municipal Device (Rate MD)	MD	362.489	219.814	236.010	(142.675)	(126.479)	-34.89%	0.01%		$ (278)	235.732	(126.757)	**-34.97%**
4	Electric Space Conditioning-Secondary Service (Rate SH)	SH	59.181.401	63.095.996	64.933.331	3.914.594	5.751.930	9.72%	4.07%		$ (76.575)	64.856.757	5.675.355	**9.59%**
5	Electric Space Conditioning-Schools (Rate SE)	SE	1.734.468	1.504.685	1.734.466	(229.783)	(1)	0.00%	0.11%		$ (2.045)	1.732.421	(2.047)	**-0.12%**
6	Water Heating-Controlled Service (Rate CB/CW)	CB	47.154	74.866	51.431	27.712	4.277	9.07%	0.00%		$ (61)	51.371	4.216	**8.94%**
7	Water Heating-Uncontrolled Service (Rate UW)	UW	125.346	142.525	137.756	17.179	12.409	9.90%	0.01%		$ (162)	137.593	12.247	**9.77%**
8	Secondary Service (Large) - (Rate SL)	SL	349.815.024	342.309.976	356.759.347	(7.505.049)	6.944.322	1.99%	22.39%		$ (420.721)	356.338.626	6.523.601	**1.86%**
9	Primary Service (Large) - (Rate PL)	PL	105.592.208	109.416.748	112.763.943	3.824.540	7.171.736	6.79%	7.08%		$ (132.981)	112.630.963	7.038.755	**6.67%**
10	Process Heating (Rate PH)	PH	2.708.603	2.793.558	2.862.205	84.954	153.602	5.67%	0.18%		$ (3.375)	2.858.830	150.227	5.55%
11	High Load Factor (Rate HL-1) (Primary Distribution)	HL1	113.099.090	111.430.648	114.551.216	(1.668.441)	1.452.127	1.28%	7.19%		$ (135.088)	114.416.128	1.317.038	**1.16%**
12	High Load Factor (Rate HL-2) (Sub transmission)	HL2	16.299.464	14.750.864	16.166.158	(1.548.600)	(133.306)	-0.82%	1.01%		$ (19.064)	16.147.094	(152.371)	**-0.93%**
13	High Load Factor (Rate HL-3) (Transmission)	HL3	20.134.611	19.167.529	20.087.229	(967.082)	(47.382)	-0.24%	1.26%		$ (23.689)	20.063.540	(71.071)	**-0.35%**
14	Automatic Protective Lighting (APL)	APL	8.808.447	11.756.332	9.680.241	2.947.885	871.793	9.90%	0.61%		$ (11.416)	9.668.825	860.378	**9.77%**
15	Municipal Lighting (MU)	MU1	$ 8.721.553	$ 13.565.255	$ 9.376.296	$ 4.843.702	$ 654.744	7.51%	0.59%		$ (11.057)	$ 9.365.239	$ 643.686	**7.38%**
16	TOTAL SYSTEM		$ 1,517,547,000	$ 1,593,511,724	$ 1,593,511,724	$ 75,964,724	$ 75,964,724	5.01%	100%	$ (1,879,203)	$ (1,879,203)	$ 1,591,632,521	$ 74,085,521	4.88%

[1] From ACOSS.
[2] Col. (E) - (C)

				Nov 22 - Settlement					ACE Capital Update					
Line No.	Rate Class		Current Revenue [1]	Unmitigated Nov 22 Settlement Revenue [1]	Mitigated Nov 22 Settlement Revenue [1]	Increase: Unmitigated - Current	Increase: Mitigated [2]	Increase: Mitigated [3]	Proportion of Nov 22 Settlement Revenue by Rate Class (%)	ACE Capital Update	Allocation of ACE Capital Update Reduction	Final Mitigated Revenue Requirement	Final Increase ($)	Final Increase (%)
	(A)	(B)	(C)	(D)	(E)	(F)	(H)							
1	Residential		656,800,000	745,657,407	706,107,213	$ 88,857,407	$ 49,307,213	7.51%	44.31%		(832,701)	705,274,511	48,474,511	**7.38%**
2	Small C&I		235,568,000	222,663,408	245,157,877	$ (12,904,592)	$ 9,589,877	4.07%	15.38%		(289,111)	244,868,766	9,300,766	**3.95%**
3	Large C&I		607,649,000	599,869,323	623,190,098	$ (7,779,677)	$ 15,541,098	2.56%	39.11%		(734,918)	622,455,180	14,806,180	**2.44%**
4	Lighting		17,530,000	25,321,587	19,056,537	$ 7,791,587	$ 1,526,537	8.71%	1.20%		(22,473)	$ 19,034,064	$ 1,504,064	**8.58%**
5	TOTAL SYSTEM		$ 1,517,547,000	$ 1,593,511,724	$ 1,593,511,724	$ 75,964,724	$ 75,964,724	5.01%	100%	$ (1,879,203)	$ (1,879,203)	$ 1,591,632,521	$ 74,085,521	4.88%

[1] From ACOSS.
[2] Col. (E) - (C)

AES Indiana
Demand Factors Used in Rate Adjustment Mechanisms
From AES Witness BR Workpaper 1.0C-R

	ECR			OSS, CAP, RTO		
	Current	Proposed	Change	Current	Proposed	Change
Demand Allocation Factors based on 12 CP Generation in COSS						
Residential	**42.48%**	**44.00%**	1.52%	**42.48%**	**44.00%**	1.52%
Small C&I	**14.10%**	**14.39%**	0.29%	**14.10%**	**14.39%**	0.29%
Large C&I - PL						
Large C&I - HL						
Large C&I - Primary	**17.62%**	**17.31%**	-0.31%	**17.62%**	**17.31%**	-0.31%
Large C&I - SL & PH						
Large C&I - Secondary	**25.39%**	**24.06%**	-1.33%	**25.39%**	**24.06%**	-1.33%
Large C&I - Total	43.01%	41.37%	-1.64%	43.01%	41.37%	-1.64%
Lighting	**0.41%**	**0.24%**	-0.17%	**0.41%**	**0.24%**	-0.17%
Total	100.00%	100.00%	0.00%	100.00%	100.00%	0.00%

AES Indiana
Revenue Percentages
Test Year Ended December 31, 2022

TDSIC Allocation Factors

(A) Rate Class	(B) Rate Code(s)	(C) Total Revenue Requirement	(D) Percent	(E) Class Revenue Allocation - Transmission	(F) Percent	(G) Class Revenue Allocation - Distribution	(H) Percent
Residential	RS, RC, RH	$ 705,274,511	44.31%	$ 38,177,210	40.06%	$ 140,721,772	59.42%
Small C&I	SS, SH, SE, CB, UW	244,868,766	15.38%	15,527,378	16.29%	36,367,900	15.36%
Large C&I - Secondary	SL, PH	359,197,456	22.57%	24,187,764	25.38%	37,029,530	15.63%
Large C&I - Primary	PL, HL	263,257,724	16.54%	17,246,697	18.10%	21,887,872	9.24%
Lighting	APL, MU1	$ 19,034,064	1.20%	$ 168,762	0.18%	$ 832,234	0.35%
TOTAL SYSTEM		$ 1,591,632,521	100.00%	$ 95,307,810	100.00%	$ 236,839,308	100.00%

Rate Code Allocations

(A) Rate Class	(B) Rate Code	(C) Total Revenue Requirement	(D) Percent	(E) Class Revenue Allocation - Transmission	(F) Percent	(G) Class Revenue Allocation - Distribution	(H) Percent
Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 705,274,511	44.31%	$ 38,177,210	40.06%	$ 140,721,772	59.42%
Secondary Service (Small) (Rate SS)	SS	177,854,893	11.17%	10,948,401	11.49%	$ 26,424,678	11.16%
Municipal Device (Rate MD)	MD	235,732	0.01%	5,218	0.01%	$ 97,289	0.04%
Electric Space Conditioning-Secondary Service (Rate SH)	SH	64,856,757	4.07%	4,451,532	4.67%	$ 9,578,626	4.04%
Electric Space Conditioning-Schools (Rate SE)	SE	1,732,421	0.11%	114,410	0.12%	$ 228,842	0.10%
Water Heating-Controlled Service (Rate CB/CW)	CB	51,371	0.00%	1,514	0.00%	$ 11,293	0.00%
Water Heating-Uncontrolled Service (Rate UW)	UW	137,593	0.01%	6,301	0.01%	$ 27,172	0.01%
Secondary Service (Large) - (Rate SL)	SL	356,338,626	22.39%	24,017,483	25.20%	$ 36,542,159	15.43%
Primary Service (Large) - (Rate PL)	PL	112,630,963	7.08%	7,603,824	7.98%	$ 11,239,522	4.75%
Process Heating (Rate PH)	PH	2,858,830	0.18%	170,281	0.18%	$ 487,372	0.21%
High Load Factor (Rate HL-1) (Primary Distribution)	HL1	114,416,128	7.19%	7,203,881	7.56%	$ 10,648,351	4.50%
High Load Factor (Rate HL-2) (Sub transmission)	HL2	16,147,094	1.01%	1,098,506	1.15%	$ -	0.00%
High Load Factor (Rate HL-3) (Transmission)	HL3	20,063,540	1.26%	1,340,486	1.41%	$ -	0.00%
Automatic Protective Lighting - APL	APL	9,668,825	0.61%	103,490	0.11%	$ 502,207	0.21%
Municipal Lighting MU-1	MU1	$ 9,365,239	0.59%	$ 65,272	0.07%	$ 330,027	0.14%
TOTAL SYSTEM		$ 1,591,632,521	100.00%	$ 95,307,810	100.00%	$ 236,839,308	100.00%

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2022

(A) Line No.	(B) Rate RS		(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)		(D) Settlement Proposed Rates
	Billed kwh				
1	First 500 kWh	$	0.118254	$	0.125421
2	Over 500 kWh	$	0.102789	$	0.113822
3	Over 1,000	$	0.090375	$	0.101408
	Resid (CR/CW)	$	0.066987	$	0.076943
	Customer Charge				
4	0 to 325 kWh	$	12.31	$	12.50
5	Over 325 kWh	$	16.75	$	17.00
	Resid (CR/CW)	$	18.22	$	20.00

(A) Line No.	(B) Rate SS		(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)		(D) Settlement Proposed Rates
	Billed kwh				
1	First 5,000 kWh	$	0.120258	$	0.122952
2	Over 5,000 kWh	$	0.105778	$	0.108472
	Customer Charge				
3	0 to 5,000 kWh	$	39.40	$	40.00
4	Over 5,000 kWh	$	54.18	$	55.00

(A) Line No.	(B) Rate MD		(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)		(D) Settlement Proposed Rates
	Billed kwh				
1	First 5,000 kWh	$	0.120258	$	0.081735
2	Over 5,000 kWh	$	0.105778	$	0.081735
	Customer Charge				
3	0 to 5,000 kWh	$	39.40	$	25.00
4	Over 5,000 kWh	$	54.18	$	25.00

(A) Line No.	(B) Rate SH		(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)		(D) Settlement Proposed Rates
	Billed kwh				
1	All kWh	$	0.112103	$	0.123516
	Customer Charge				
2	All Customers	$	54.18	$	55.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2022

	(A)	(B)	(C)	(D)
Line No.	Rate SE		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		First 5,000 kWh	$ 0.133466	$ 0.133318
2		Over 5,000 kWh	$ 0.118986	$ 0.118838
3		Excess of 155 x Car	$ 0.105294	$ 0.105146
	Customer Charge			
4		All Customers	$ 54.18	$ 55.00

	(A)	(B)	(C)	(D)
Line No.	Rate UW		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.081263	$ 0.089471
	Customer Charge			
2		All Customers	$ 36.45	$ 40.00

	(A)	(B)	(C)	(D)
Line No.	Rate CB		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.070773	$ 0.076943
	Customer Charge			
2		All Customers	$ 18.22	$ 20.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2022

	(A)	(B)	(C)	(D)
Line No.	Rate SL		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.048879	$ 0.041430
	Billed kW			
2		All kW	$ 21.10	$ 24.74
	Customer Charge			
3		All Customers	$ 118.20	$ 120.00

	(A)	(B)	(C)	(D)
Line No.	Rate PL		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.047118	$ 0.040836
	Billed kW			
2		All kW	$ 22.88	$ 28.30
	Customer Charge			
3		All Customers	$ 118.20	$ 130.00

	(A)	(B)	(C)	(D)
Line No.	Rate PH		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		First 250 Hrs use	$ 0.091886	$ 0.097390
2		Additional kWh	$ 0.077110	$ 0.082614
	Customer Charge			
3		All Customers	$ 1,231.26	$ 1,250.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2022

Line No.	(A) Rate HL1	(B)	(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	(D) Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.046765	$ 0.040606
	Billed kW			
2		All kW	$ 22.88	$ 27.95
	Customer Charge			
3		All Customers	$ 132.98	$ 130.00

Line No.	(A) Rate HL2	(B)	(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	(D) Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.046588	$ 0.040410
	Billed kW			
2		All kW	$ 22.15	$ 25.00
	Customer Charge			
3		All Customers	$ 211.78	$ 215.00

Line No.	(A) Rate HL3 - High Load Factor	(B)	(C) Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	(D) Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.046165	$ 0.039873
	Billed kW			
2		All kW	$ 21.30	$ 24.09
	Customer Charge			
3		All Customers	$ 492.51	$ 500.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2022

	(A)	(B)	(C)	(D)
Line No.	HL4		Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)	Settlement Proposed Rates
	Billed kwh			
1		All kWh	$ 0.058350	$ 0.060210
	Billed kW			
2		All kW	$ 14.59	$ 15.06
	Customer Charge			
3		All Customers	$ 492.51	$ 508.21

AES Indiana
Lighting Rate Design

Code	Description	Inventory (Light Count)	Proposed Annual Rate	Proposed Revenue
(A)	(B)	(C)	(F)	(G)
APL				
	Company Installed, Owned, and Maintained (APL)			
68	175 WATT LIGHT	9,251	$119.40	$1,104,569
69	400 WATT MV REDDY SENT.	1,245	$228.96	$285,055
70	1000 WATT MV REDDY SENT.	75	$416.28	$31,221
71	100 WATT LIGHT	6,316	$102.60	$648,022
72	150 WATT HPS REDDY SENT.	975	$213.24	$207,909
73	250 WATT HPS REDDY SENT.	1,027	$285.72	$293,434
74	400 WATT HPS REDDY SENT.	1,115	$336.60	$375,309
78	175 WATT MV - SEC. METERED - OVERHEAD	68	$79.20	$5,386
79	400 WATT MV - SEC. METERED OVERHEAD	16	$153.48	$2,456
80	1000 WATT MV - SEC. METERED - OVERHEAD	1	$237.84	$238
81	100 WATT HPS - SEC. METERED - OVERHEAD	19	$82.08	$1,560
82	150 WATT HPS - SEC. METERED - OVERHEAD	1	$187.56	$188
83	250 WATT HPS - SEC. METERED - OVERHEAD	2	$237.12	$474
84	400 WATT HPS - SEC. METERED - OVERHEAD	12	$261.48	$3,138
85	ENERGY AND CONTROL ONLY	1	$46.32	$46
86	400 WATT MV FLOOD - OVERHEAD	495	$229.20	$113,454
87	150 WATT HPS FLOOD - OVERHEAD	490	$213.84	$104,782
88	250 WATT HPS FLOOD - OVERHEAD	707	$285.84	$202,089
89	400 WATT HPS FLOOD - OVERHEAD	5,792	$336.54	$1,949,240
90	400 WATT METAL HALIDE FLOOD - OVERHEAD	1,044	$335.40	$350,158
91	400 WATT MV FLOOD - SEC. METERED	6	$153.48	$921
92	150 WATT HPS FLOOD - SEC. METERED	1	$187.56	$188
93	250 WATT HPS FLOOD - SEC. METERED	6	$237.12	$1,423
94	400 WATT HPS FLOOD - SEC. METERED	36	$261.48	$9,413
95	400 WATT METAL HALIDE FLOOD-SEC. METERED	2	$261.48	$523
96	- WOOD POLE WITH OVERHEAD FEED -	7,555	$53.40	$403,437
97	- WOOD POLE WITH UNDERGROUND FEED -	815	$131.88	$107,482
126	1000 WATT MV - 1ST FIXTURE	0	$52.08	$0
127	400 WATT MV-1ST FIXTURE	13	$327.36	$4,256
128	175 WATT MV-1ST FIXTURE	3	$256.92	$771
129	400 WATT HPS-1ST FIXTURE	133	$464.64	$61,797
130	250 WATT HPS-1ST FIXTURE	202	$312.12	$63,048
131	150 WATT HPS-1ST FIXTURE	182	$265.20	$48,266
132	100 WATT HPS-1ST FIXTURE	32	$241.32	$7,722
135	400 WATT HPS-1ST FIXTURE-SHOEBOX	91	$390.00	$35,490
136	250 WATT HPS-1ST FIXTURE-SHOEBOX	103	$314.04	$32,346
137	400 WATT METAL HALIDE-1ST FIX-SHOEBOX	370	$388.68	$143,812
138	400 WATT MV-1ST FIXTURE-FLOOD	3	$327.36	$982
139	150 WATT HPS-1ST FIXTURE-FLOOD	12	$265.20	$3,182
140	250 WATT HPS-1ST FIXTURE-FLOOD	63	$312.12	$19,664
141	400 WATT HPS-1ST FIXTURE-FLOOD	237	$464.64	$110,120
142	400 WATT METAL HALIDE-1ST FIX-FLOOD	89	$388.68	$34,593

AES Indiana
Lighting Rate Design

143 1000 WATT MV - ADDITIONAL FIXTURE	0	$52.08	$0
144 400 WATT MV-ADDIT'L FIXTURE	1	$228.96	$229
145 175 WATT MV-ADDIT'L FIXTURE	2	$119.40	$239
146 400 WATT HPS-ADDIT'L FIXTURE	49	$336.60	$16,493
147 250 WATT HPS-ADDIT'L FIXTURE	16	$285.72	$4,572
148 150 WATT HPS-ADDIT'L FIXTURE	14	$213.24	$2,985
149 100 WATT HPS-ADDIT'L FIXTURE	3	$102.60	$308
152 400 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	16	$155.52	$2,488
153 250 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	9	$118.08	$1,063
154 400 WATT METAL HALIDE-ADDT'L FIX-SHOEBOX	110	$154.08	$16,949
155 400 WATT MV-ADDIT'L FIXTURE-FLOOD	2	$228.96	$458
156 150 WATT HPS-ADDIT'L FIXTURE-FLOOD	9	$213.24	$1,919
157 250 WATT HPS-ADDIT'L FIXTURE-FLOOD	55	$285.72	$15,715
158 400 WATT HPS-ADDIT'L FIXTURE-FLOOD	259	$336.60	$87,179
159 400 WATT METAL HALIDE-ADDT'L FIX-FLOOD	185	$154.08	$28,505
160 175 W MV POST TOP WASH	40	$384.00	$15,360
161 175 W MV POST TOP	29	$250.32	$7,259
162 100 W HPS POST TOP WASH	57	$370.56	$21,122
163 100 W HPS POST TOP	407	$240.36	$97,827
164 150 W HPS POST TOP WASH	114	$427.68	$48,756
165 150 W HPS POST TOP BALL	60	$297.48	$17,849
180 250 WATT MET HAL 18 FT DIR EMBEDDED	3	$701.40	$2,104
181 250 WATT MET HAL 12 FT ANCHOR BASED	11	$768.12	$8,449
182 2-250 WATT MET HAL 18 FT DIR EMBEDDED	7	$978.60	$6,850
183 2-250 WATT MET HAL 12 FT ANCHOR BASED	0	$1,044.96	$0
188 250 WATT MET HAL 18 FT DIR EMBED PRI METER	0	$638.88	$0
189 250 WATT MET HAL 12 FT ANCHOR BASE PRI METER	0	$705.36	$0
190 2-250 WATT MET HAL 18 FT DIR EMBED PRI METER	0	$861.00	$0
191 2-250 WATT MET HAL 12 FT ANCHOR BASE PRI METER	0	$927.72	$0
271 100 WATT LIGHT	2,028	$203.40	$412,495
272 150 WATT HPS REDDY SENT.	162	$232.92	$37,733
273 250 WATT HPS REDDY SENT.	327	$281.64	$92,096
274 400 WATT HPS REDDY SENT.	221	$345.60	$76,378
287 150 WATT HPS FLOOD - OVERHEAD	71	$239.52	$17,006
288 250 WATT HPS FLOOD - OVERHEAD	123	$286.92	$35,291
289 400 WATT HPS FLOOD - OVERHEAD	1,625	$349.68	$568,230
296 - WOOD POLE WITH OVERHEAD FEED -	1,449	$91.32	$132,323
297 - WOOD POLE WITH UNDERGROUND FEED -	92	$115.56	$10,632
300 LED COBRA HEAD 5000-6000 LUMENS	745	$219.84	$163,781
301 LED COBRA HEAD 6500-7500 LUMENS	85	$226.08	$19,217
302 LED COBRA HEAD 12500-13500 LUMENS	81	$278.52	$22,560
303 LED COBRA HEAD 20000-21500 LUMENS	208	$324.96	$67,592
304 LED AREA LIGHT 11500-16500 LUMENS	0	$304.92	$0
305 LED AREA LIGHT 21000-26000 LUMENS	55	$342.00	$18,810
306 LED TRAD. POST TOP 6000-7500 LUMENS	5	$276.48	$1,382
307 LED TWIN WASH POST TOP 2 @ 6000-7500-LT	0	$683.88	$0
308 LED WASH POST TOP 6000-7500 LUMENS	0	$373.08	$0
313 LED FLOOD 11,500 - 16,500 LUMENS	48	$297.96	$14,302
314 LED FLOOD 21,000 - 26,000 LUMENS	1,216	$332.28	$404,052
328 12' FG TRAD COL PAIRED W/LT	2	$84.60	$169
329 400 WATT HPS-1ST FIXTURE	17	$480.24	$8,164
330 250 WATT HPS-1ST FIXTURE	25	$416.40	$10,410

AES Indiana
Lighting Rate Design

331 150 WATT HPS-1ST FIXTURE	15	$373.32	$5,600
332 100 WATT HPS-1ST FIXTURE	0	$339.72	$0
333 400 WATT HPS - 1ST FIXTURE PAINTED BRONZ	0	$582.36	$0
334 250 WATT HPS - 1ST FIXTURE PAINTED BRONZ	0	$528.00	$0
335 400 WATT HPS-1ST FIXTURE-SHOEBOX	13	$477.00	$6,201
336 250 WATT HPS-1ST FIXTURE-SHOEBOX	10	$412.32	$4,123
337 12' FG FLUTED COL CUST BASE PAIRED W/LT	0	$171.36	$0
339 150 WATT HPS-1ST FIXTURE-FLOOD	4	$482.04	$1,928
340 250 WATT HPS-1ST FIXTURE-FLOOD	2	$517.20	$1,034
341 400 WATT HPS-1ST FIXTURE-FLOOD	79	$561.60	$44,366
342 14' AL FLUTED COL CUST BASE PAIRED W/LT	0	$16.56	$0
343 14 FG FLUTED COL DIRECT BURY PAIRED W/LT	0	$174.00	$0
344 14 FG SMOOTH COL DIRECT BURY PAIRED W/LT	0	$149.76	$0
346 400 WATT HPS-ADDIT'L FIXTURE	35	$354.60	$12,411
347 250 WATT HPS-ADDIT'L FIXTURE	9	$290.76	$2,617
348 150 WATT HPS-ADDIT'L FIXTURE	1	$247.80	$248
349 100 WATT HPS-ADDIT'L FIXTURE	0	$218.16	$0
350 400 WATT HPS -ADDITIONAL FIXTURE-PAINTED	0	$345.12	$0
351 250 WATT HPS -ADDITIONAL FIXTURE-PAINTED	0	$290.76	$0
352 400 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	0	$348.12	$0
353 250 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	0	$283.44	$0
354 AL COL W/BASE PAIRED W/LT	40	$211.80	$8,472
355 AL COL ON CUST OWNED BASE PAIRED W/LT	8	$118.08	$945
356 150 WATT HPS-ADDIT'L FIXTURE-FLOOD	0	$254.88	$0
357 250 WATT HPS-ADDIT'L FIXTURE-FLOOD	2	$302.40	$605
358 400 WATT HPS-ADDIT'L FIXTURE-FLOOD	140	$365.16	$51,122
362 100 W HPS POST TOP WASH	20	$384.00	$7,680
363 100 W HPS POST TOP	5	$286.92	$1,435
364 150 W HPS POST TOP WASH	28	$407.28	$11,404
365 150 W HPS POST TOP BALL	0	$365.16	$0
369 AL COL BZ W/BASE PAIRED W/LT	0	$231.00	$0
370 AL COL BZ ON CUST BASE PAIRED W/LT	29	$137.28	$3,981
378 FG COL DIRECT BURY PAIRED W/LT	74	$126.60	$9,368
380 250 WATT MET HAL 18 FT DIR EMBEDDED	88	$486.48	$42,810
381 250 WATT MET HAL 12 FT ANCHOR BASED	140	$483.72	$67,721
382 2-250 WATT MET HAL 18 FT DIR EMBEDDED	80	$717.72	$57,418
383 2-250 WATT MET HAL 12 FT ANCHOR BASED	13	$714.96	$9,294
388 250 WATT MH 18 FT DIR EMBED PRI METER	32	$389.52	$12,465
389 250 WATT MH 12 FT ANCHOR BASE PRI METER	16	$386.76	$6,188
390 2-250 WATT MH 18 FT DIR EMBED PRI METER	17	$523.80	$8,905
391 2-250 WATT MH 12 FT ANCHOR BASE PRI MTR	9	$521.04	$4,689
Total APL	**49,558**		**$9,668,492**
		Target	**$9,668,794**
		Over (Under) Recovery	($303)

MU

Company Installed, Owned, and Maintained (MU-1)

1 1000 WATT MV - OVERHEAD	1	$370.92	$371
2 1000 WATT MV - TRAFFIC COLUMN	0	$333.60	$0
3 1000 WATT MV - METAL COLUMN	3	$516.60	$1,550
4 400 WATT MV - OVERHEAD	16	$196.80	$3,149
5 400 WATT MV - TRAFFIC COLUMN	0	$179.16	$0

AES Indiana
Lighting Rate Design

6	400 WATT MV - METAL COLUMN	144	$264.96	$38,154
7	175 WATT MV - OVERHEAD	446	$130.92	$58,390
8	175 WATT MV - TRAFFIC COLUMN	0	$121.32	$0
9	175 WATT MV - METAL COLUMN	670	$205.68	$137,806
10	175 W MV - POST TOP	476	$200.52	$95,448
11	175 W MV - POST TOP WASH	189	$306.00	$57,834
12	400 WATT HPS - OVERHEAD	240	$227.40	$54,576
13	400 WATT HPS - TRAFFIC COLUMN	65	$227.40	$14,781
14	400 WATT HPS - METAL COLUMN	552	$373.08	$205,940
15	250 WATT HPS - OVERHEAD	505	$180.96	$91,385
16	250 WATT HPS - TRAFFIC COLUMN	36	$180.96	$6,515
17	250 WATT HPS - METAL COLUMN	619	$250.44	$155,022
18	150 WATT HPS - OVERHEAD	491	$140.04	$68,760
19	150 WATT HPS - TRAFFIC COLUMN	7	$140.04	$980
20	150 WATT HPS - METAL COLUMN	472	$211.80	$99,970
21	100 WATT HPS - OVERHEAD	796	$117.48	$93,514
22	100 WATT HPS - TRAFFIC COLUMN	1	$117.48	$117
23	100 WATT HPS - METAL COLUMN	517	$192.24	$99,388
24	100 W HPS - POST TOP	5,857	$191.28	$1,120,327
25	100 W HPS - POST TOP WASH	1,703	$293.88	$500,478
26	150 W HPS- POST TOP BALL	21	$232.92	$4,891
27	150 W HPS - POST TOP WASH	3,037	$339.84	$1,032,094
28	3-150 WATT HPS-1 COLUMN CLUSTER W/BALAST	0	$561.00	$0
29	3-150 WATT HPS-2 COLUMN CLUSTER N/BALAST	0	$561.00	$0
30	3-150 WATT HPS-2 COLUMN CLUSTER W/BALAST	0	$561.00	$0
32	1-150 & 4-100 WATT HPS - CLUSTER	1	$781.56	$782
33	400 WATT HPS-METAL COLUMN-PAINTED BRONZE	74	$404.28	$29,917
34	400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	8	$232.56	$1,860
35	250 WATT HPS-METAL COLUMN-PAINTED BRONZE	1	$281.64	$282
37	175 WATT MV - FIBERGLASS COLUMN	6	$196.32	$1,178
38	100 WATT HPS - FIBERGLASS COLUMN	103	$182.88	$18,837
39	150 WATT HPS - FIBERGLASS COLUMN	155	$202.32	$31,360
40	250 WATT HPS - FIBERGLASS COLUMN	124	$241.20	$29,909
41	400 WATT HPS - FIBERGLASS COLUMN	159	$348.36	$55,389
42	400 WATT MH SHOEBOX - FIBERGLASS COLUMN	103	$319.80	$32,939
43	2-400 WATT MH SHOEBOX-FIBERGLASS COLUMN	48	$454.20	$21,802
44	175 WATT MV UPASS 4100HRS - WALL MOUNTED	0	$156.60	$0
45	150 WATT HPS UPASS 4100HRS -WALL MOUNTED	192	$180.48	$34,652
46	250 W HPS - SHOEBOX	10	$252.00	$2,520
48	2-250 W HPS-SHOEBOX	0	$323.16	$0
50	400 WATT HPS UPASS 8760HRS WALL MOUNTED	85	$421.92	$35,863
51	150 WATT HPS UPASS 8760HRS WALL MOUNTED	101	$242.40	$24,482
65	400 W HPS - SHOEBOX	43	$314.28	$13,514
66	2-400 W HPS-SHOEBOX	15	$443.52	$6,653
101	400 WATT METAL HALIDE - METAL COLUMN	0	$371.88	$0
184	EXCESS MATERIAL FOR CIRCLE CENTRE MALL	1	$6,291.12	$6,291
185	PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	47	$810.48	$38,093
187	TWIN 80W LED POST TOP	53	$791.28	$41,938
200	LED COBRA HEAD 5000-6000 LUMENS	1,226	$213.63	$261,905
201	LED COBRA HEAD 6500-7500 LUMENS	462	$219.31	$101,321
202	LED COBRA HEAD 12500-13500 LUMENS	460	$266.64	$122,654
203	LED COBRA HEAD 20000-21500 LUMENS	171	$308.63	$52,776

AES Indiana
Lighting Rate Design

204 LED AREA LIGHT 11500-16500 LUMENS	0	$287.71	$0
205 LED AREA LIGHT 21000-26000 LUMENS	31	$321.02	$9,952
206 LED TRAD. POST TOP 6000-7500 LUMENS	336	$262.09	$88,063
207 LED TWIN WASH POST TOP 2 @ 6000-7500-LT	35	$632.93	$22,153
208 LED WASH POST TOP 6000-7500 LUMENS	138	$350.10	$48,313
212 400 WATT HPS - OVERHEAD	4	$450.72	$1,803
213 400 WATT HPS - TRAFFIC COLUMN	0	$409.32	$0
214 400 WATT HPS - METAL COLUMN	32	$577.92	$18,493
215 250 WATT HPS - OVERHEAD	25	$388.20	$9,705
216 250 WATT HPS - TRAFFIC COLUMN	0	$346.68	$0
217 250 WATT HPS - METAL COLUMN	42	$515.40	$21,647
218 150 WATT HPS - OVERHEAD	12	$346.08	$4,153
219 150 WATT HPS - TRAFFIC COLUMN	0	$304.68	$0
220 150 WATT HPS - METAL COLUMN	1	$473.28	$473
221 100 WATT HPS - OVERHEAD	27	$316.92	$8,557
222 100 WATT HPS - TRAFFIC COLUMN	0	$275.40	$0
223 100 WATT HPS - METAL COLUMN	31	$444.00	$13,764
224 100 W HPS - POST TOP	211	$304.20	$64,186
225 100 W HPS - POST TOP WASH	117	$405.36	$47,427
226 150 W HPS- POST TOP BALL	0	$384.24	$0
227 150 W HPS - POST TOP WASH	247	$428.04	$105,726
228 12' FG TRAD COL PAIRED W/LT	336	$88.08	$29,595
232 1-150 & 4-100 WATT HPS - CLUSTER	0	$960.12	$0
233 400 WATT HPS-METAL COLUMN-PAINTED BRONZE	0	$603.60	$0
234 400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	0	$347.04	$0
235 250 WATT HPS-METAL COLUMN-PAINTED BRONZE	0	$550.92	$0
236 250 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	0	$284.52	$0
237 12' FG FLUTED COL CUST BASE PAIRED W/LT	0	$178.32	$0
238 100 WATT HPS - FIBERGLASS COLUMN	2	$359.04	$718
239 150 WATT HPS - FIBERGLASS COLUMN	13	$392.64	$5,104
240 250 WATT HPS - FIBERGLASS COLUMN	0	$434.76	$0
241 400 WATT HPS - FIBERGLASS COLUMN	1	$497.28	$497
242 14' AL FLUTED COL CUST BASE PAIRED W/LT	52	$206.40	$10,733
243 14 FG FLUTED COL DIRECT BURY PAIRED W/LT	14	$181.20	$2,537
244 14 FG SMOOTH COL DIRECT BURY PAIRED W/LT	88	$155.76	$13,707
245 150 WATT HPS UPASS 4100HRS -WALL MOUNTED	0	$285.00	$0
246 250 W HPS - SHOEBOX	0	$430.56	$0
248 2-250 W HPS-SHOEBOX	0	$493.20	$0
250 400 WATT HPS UPASS 8760HRS WALL MOUNTED	0	$538.68	$0
251 150 WATT HPS UPASS 8760HRS WALL MOUNTED	0	$330.12	$0
254 AL COL W/BASE PAIRED W/LT	122	$220.56	$26,908
255 AL COL ON CUST OWNED BASE PAIRED W/LT	1	$122.88	$123
265 400 W HPS - SHOEBOX	1	$493.92	$494
266 2-400 W HPS-SHOEBOX	0	$709.44	$0
269 AL COL BZ W/BASE PAIRED W/LT	0	$240.48	$0
270 AL COL BZ ON CUST BASE PAIRED W/LT	0	$142.92	$0
278 FG COL DIRECT BURY PAIRED W/LT	104	$131.88	$13,716
385 PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	0	$460.68	$0
386 80W LED POST TOP	0	$682.44	$0
396 WD POLE W/OH FEED-W/OR W/O LT	923	$94.80	$87,500
397 WD POLE W/UG FEED-PAIRED W/LT	109	$120.12	$13,093

AES Indiana
Lighting Rate Design

	Streetlighting with CIAC - City of Indianapolis			
400	LED COBRA HEAD 5000-6000 LUMENS	13,346	$91.68	$1,223,506
401	LED COBRA HEAD 6500-7500 LUMENS	1,847	$95.64	$176,647
402	LED COBRA HEAD 12500-13500 LUMENS	6,422	$112.09	$719,836
403	LED COBRA HEAD 20000-21500 LUMENS	3,854	$131.51	$506,837
404	LED AREA LIGHT 11500-16500 LUMENS	3	$111.74	$335
405	LED AREA LIGHT 21000-26000 LUMENS	6	$135.06	$810
406	LED TRAD. POST TOP 6000-7500 LUMENS	0	$99.94	$0
407	LED TWIN WASH POST TOP 2 @ 6000-7500 L	0	$116.11	$0
408	LED WASH POST TOP 6000-7500 LUMENS	0	$96.40	$0
409	LED COBRA 12500-13500 L-OH FROM 215	12	$218.17	$2,618
410	LED COBRA 12500-13500L-METAL COL FRM 217	2	$344.65	$689
411	LED COBRA 6500-7500 L-OH FROM 218	12	$201.60	$2,419
412	LED COBRA 5000-6000 L-OH FROM 221	72	$197.76	$14,238
	Streetlighting with CIAC - Non-City of Indianapolis			
400	LED COBRA HEAD 5000-6000 LUMENS	1,287	$106.68	$137,292
401	LED COBRA HEAD 6500-7500 LUMENS	273	$110.64	$30,205
402	LED COBRA HEAD 12500-13500 LUMENS	563	$127.09	$71,551
403	LED COBRA HEAD 20000-21500 LUMENS	121	$146.51	$17,728
404	LED AREA LIGHT 11500-16500 LUMENS	30	$126.74	$3,802
405	LED AREA LIGHT 21000-26000 LUMENS	0	$150.06	$0
406	LED TRAD. POST TOP 6000-7500 LUMENS	40	$114.94	$4,598
407	LED TWIN WASH POST TOP 2 @ 6000-7500 L	0	$131.11	$0
408	LED WASH POST TOP 6000-7500 LUMENS	162	$111.40	$18,046
409	LED COBRA 12500-13500 L-OH FROM 215	0	$233.17	$0
410	LED COBRA 12500-13500L-METAL COL FRM 217	0	$359.65	$0
411	LED COBRA 6500-7500 L-OH FROM 218	0	$216.60	$0
412	LED COBRA 5000-6000 L-OH FROM 221	0	$212.76	$0
	Customer Installed, Owned, and Maintained (MU-1)			
55	250 WATT MV - CUSTOMER OWNED	2	$166.68	$333
56	175 WATT MV - CUSTOMER OWNED	26	$105.60	$2,746
59	400 WATT HPS - CUSTOMER OWNED	477	$168.24	$80,250
60	250 WATT HPS - CUSTOMER OWNED	270	$130.68	$35,284
61	150 WATT HPS - CUSTOMER OWNED	253	$97.56	$24,683
63	1000 WATT HPS - CUSTOMER OWNED	276	$354.12	$97,737
64	175 WATT MV ORNIMENTAL - CUSTOMER OWNED	2	$156.96	$314
109	400 WATT HPS-CUSTOMER OWNED WO/MAINT	56	$147.72	$8,272
111	150 WATT HPS - CUSTOMER OWNED WO/MAINT	0	$77.28	$0
112	1000 WATT HPS - CUSTOMER OWNED WO/MAINT	0	$297.72	$0
	Customer Installed, Owned, but Company Maintained (MU-1)			
120	400 WATT HPS - CUSTOMER OWNED W/MAINT	13	$168.24	$2,187
	Total MU-1	52,994		$8,760,460

Code	Description	Inventory	Proposed Price Per Watt	Proposed Revenue

AES Indiana
Lighting Rate Design
Customer Installed, Owned, and Maintained (MU-4)

Total MU-4	1,312	$ 0.78	$604,465
MU-4 Watts	774,956		
Total MU	54,306		$9,364,925
		Target	$9,365,209
		Over (Under) Recovery	($284)
Grand Total Lighting (APL and MU)	103,864		$19,033,417

Code	Description	Minimum Wattage	Minimum Per Fixture or Device
	Customer Installed, Owned, and Maintained (MU-4)		
	MU-4 Rate Calculation	60	$ 46.80

AES Indiana
Proposed Rates - Residential Bill Impacts - RS Customers
Test year Ending December 31, 2022

Proposed Rates

		Including Fuel		Including Fuel & DSM		Excluding Fuel	
Energy Charge		Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate
First 500 kWh		$ 0.118254	$ 0.125421	$ 0.120988	$ 0.128155	$ 0.081961	$ 0.091102
Over 500 kWh	500	$ 0.102789	$ 0.113822	$ 0.105523	$ 0.116556	$ 0.066496	$ 0.079503

[1] Includes riders rolled into base rates (TDSIC, ECCR, DSM, CAP, RTO and FAC)

Customer Charge		Including Fuel		Including Fuel & DSM	
0 to 325 kWh		$ 12.31	$ 12.50	$ 12.31	$ 12.50
Over 325 kWh	325	$ 16.75	$ 17.00	$ 16.75	$ 17.00

DSM Charge ($/kWh)	$ 0.002734

Bill Impacts for RS Customers

			Including Fuel & DSM					Excluding Fuel				
			Monthly Margin or Base Rate		Increase / <Decrease>			Monthly Total Bill		Increase / <Decrease>		
Line No.	Monthly kWh	% of Customers	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	4.63%	$ 24.41	$ 25.32	$ 0.91	3.73%	0.25320	$ 20.51	$ 21.61	$ 1.10	5.36%	0.21610
2	200	4.36%	36.51	38.13	1.62	4.44%	0.19065	28.70	30.72	2.02	7.04%	0.15360
3	400	15.29%	65.15	68.26	3.11	4.77%	0.17065	49.53	53.44	3.91	7.89%	0.13360
4	600	20.59%	87.79	92.74	4.95	5.64%	0.15457	64.38	70.50	6.12	9.51%	0.11750
5	800	18.66%	108.90	116.05	7.15	6.57%	0.14506	77.68	86.40	8.72	11.23%	0.10800
7	1,000	13.29%	130.00	139.36	9.36	7.20%	0.13936	90.98	102.30	11.32	12.44%	0.10230
8	1,200	8.69%	151.11	162.67	11.56	7.65%	0.13556	104.28	118.20	13.92	13.35%	0.09850
9	1,500	7.23%	182.76	197.64	14.88	8.14%	0.13176	124.23	142.05	17.82	14.34%	0.09470
10	1,800	3.45%	214.42	232.60	18.18	8.48%	0.12922	144.17	165.90	21.73	15.07%	0.09217
11	2,000	1.30%	235.52	255.91	20.39	8.66%	0.12796	157.47	181.80	24.33	15.45%	0.09090
12	2,400	1.30%	277.73	302.54	24.81	8.93%	0.12606	184.07	213.61	29.54	16.05%	0.08900
13	2,700	0.46%	309.39	337.50	28.11	9.09%	0.12500	204.02	237.46	33.44	16.39%	0.08795
14	3,000	0.28%	341.05	372.47	31.42	9.21%	0.12416	223.97	261.31	37.34	16.67%	0.08710
15	4,000	0.32%	446.57	489.03	42.46	9.51%	0.12226	290.47	340.81	50.34	17.33%	0.08520
16	5,000	0.08%	552.09	605.58	53.49	9.69%	0.12112	356.96	420.31	63.35	17.75%	0.08406
17	7,000	0.05%	763.14	838.69	75.55	9.90%	0.11981	489.95	579.32	89.37	18.24%	0.08276
18	>7,000	0.03%										
	Average											
19	748		103.43	110.00	6.57	6.35%	0.14703	74.23	82.28	8.05	10.84%	0.10998