

ORIGINAL

Commissioner	Yes	No	Not Participating
Zay	√		
Deig		√	
Swinger			√
Veleta	√		
Ziegner	√		

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 THROUGH A PHASE-IN)
RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED)
RELIEF, INCLUDING (1) REVISED DEPRECIATION)
RATES, INCLUDING COST OF REMOVAL LESS SALVAGE)
AND UPDATED DEPRECIATION EXPENSE; (2))
ACCOUNTING RELIEF, INCLUDING DEFERRALS AND)
AMORTIZATIONS, (3) INCLUSION OF CAPITAL)
INVESTMENT, (4) RATE ADJUSTMENT MECHANISM)
PROPOSALS, INCLUDING A NEW PROPERTY TAX RIDER,)
AND (5) NEW SCHEDULES OF RATES, RULES AND)
REGULATIONS FOR SERVICE.)**

CAUSE NO. 46258

APPROVED: JUN 17 2026

ORDER OF THE COMMISSION

Presiding Officers:

Andy Zay, Chairman

David E. Veleta, Commissioner

Kristin E. Kresge, Administrative Law Judge

On June 3, 2025, Indianapolis Power & Light Company d/b/a AES Indiana (“AES Indiana” or “Petitioner”) filed its Verified Petition with the Indiana Utility Regulatory Commission (“Commission”) initiating this Cause. Contemporaneously, AES Indiana filed its prepared testimony and attachments from the following witnesses, as well as supporting workpapers and minimum standard filing requirements information:

- Brandi Davis-Handy, President, AES Indiana;
- David C. Peters, Senior Director of Financial Planning and Analysis and Transactions, AES US Services, LLC (“AES Services”);
- Michael E. Russo, Senior Forecast Consultant, Itron, Inc.;
- Kimberly Aliff, Revenue Requirements Manager, AES Indiana;
- Adrien M. McKenzie, President, Financial Concepts and Applications, Inc.;
- Dustin J. Illyes, Treasurer of US Utilities, including AES Indiana, AES US Services;
- Nicholas M. Miller, Director, Tax, AES US Utilities, AES Services;
- John J. Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC;
- Alexander J. Dickerson, Senior Manager, Wholesale Energy, AES Indiana;
- Caleb Steiner, Director, Regulated Operations and Term Management, US Utilities, AES Services;
- Andrew Baillie, Program Director, Global Insurance, AES Services;

- Hampton Matthew Roach, Senior Director, Global Benefits, AES Services;
- Cody A. Flint, Manager, Vegetation Management, AES Indiana;
- Matthew J. Dalton, Director, Human Resources, AES Services;
- Michael L. Holtsclaw, Director, Power Delivery Operations, AES Indiana;
- Gregory Ellis, Director of Generation for Harding Street Station; Georgetown Station and Eagle Valley Station, AES Indiana;
- David Faller, Assistant Controller, AES US Utilities, AES Services;
- Paula M. Guletsky, Vice President and Project Director for AES Indiana, Sargent & Lundy LLC (“S&L”);
- David Barrie, Director of Advisory Services in Americas region, Wood Canada Limited;
- Austin J. Baker, Manager, Regulatory Affairs, AES Indiana¹; and
- Bickey Rimal, Vice President, Concentric Energy Advisors, Inc.

On June 6, 2025, Citizens Action Coalition of Indiana, Inc. (“CAC”) filed a Petition to Intervene, which was granted by the Presiding Officers by docket entry dated June 25, 2025.

On June 11, 2025, the Indiana Office of the Utility Consumer Counselor (“OUCC”) filed a Motion to Conduct Multiple Public Field Hearings, and on June 25, 2025, the OUCC filed Supplemental Support to their Motion to Conduct Multiple Public Field Hearings. Docket entries setting the field hearings were issued on August 1 and 7, 2025. Docket entries Tendering Ex Parte Communications were entered on June 25, 2025, July 9, 2025, September 9, 2025, October 24, 2025, November 3, 2025, and March 5, 2026.

On July 1, 2025, the Kroger Co. (“Kroger”) filed its Petition to Intervene, and on July 2, 2025, both the AES Indiana Industrial Group (“IG”), an ad hoc group of large volume users, and Walmart Inc. (“Walmart”) filed Petitions to Intervene; all of which were granted by docket entries on July 10, 2025.

On July 16, 2025, the City of Indianapolis filed its Petition to Intervene, which was granted by docket entry on August 1, 2025.

Field hearings were conducted on August 18, 21, 25 and 27, 2025 in Indianapolis, Indiana, the largest municipality in Petitioner’s service area. These field hearings were held in Perry Township, Center Township, Pike Township, and Lawrence Township, respectfully. At those field hearings, members of the public provided statements and related exhibits to the Commission under oath.

On September 4, 2025, Rolls-Royce Corporation (“Rolls-Royce”) filed its Petition to Intervene, which was granted on September 10, 2025.

¹ The direct testimony filed by witness Baker was subsequently adopted by AES Indiana Witness Aliff. Petitioner’s Notice of Substitution of Witness and Submission of Associated Revisions to Testimony (Oct. 8, 2025). AES Indiana filed corrections to its prefiled testimony in this Cause on August 15, 2025, September 4, 2025, September 8, 2025, October 6, 2025, October 8, 2025, December 17, 2025, January 22, 2026 and January 27, 2026.

On September 9, 2025, the OUCC and certain Intervenors filed their respective cases-in-chief. The OUCC provided testimony and attachments from the following witnesses:

- Brian R. Latham, Director, Electric Division;
- Michael D. Eckert, Chief Technical Advisor, Electric Division;
- Kaleb G. Lantrip, Senior Utility Analyst, Electric Division;
- Brittany L. Baker, Utility Analyst, Electric Division;
- Roopali Sanka, Utility Analyst, Electric Division;
- Derek J. Leader, Utility Analyst;
- Patrick A. Kelley, Utility Analyst;
- Leja D. Courter, Chief Technical Advisor;
- James S. Garren, Consultant, GDS Associates, Inc.;
- Michael W. Deupree, Senior Research Consultant, Acadian Consulting Group; and
- Ashley L. Bishop, External Affairs Specialist.

The IG provided testimony and attachments from the following witnesses:

- Brian C. Andrews, Principal, Brubaker & Associates, Inc.;
- Jessica A. York, Principal, Brubaker & Associates, Inc.; and
- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc.

CAC prefiled the testimony and attachments of Benjamin Inskeep, Program Director for CAC, and Justin Barnes, President of EQ Research LLC. In accordance with the docket entry dated September 12, 2025, CAC filed limited supplemental testimony of Mr. Barnes on September 19, 2025.

Kroger prefiled the testimony and attachments of Jared R. Robertson, Senior Consultant for Energy Strategies, LLC. Kroger filed an unopposed Motion to Substitute Justin Bieber of Energy Strategies, LLC for Mr. Robertson on December 22, 2025. Kroger's Motion was granted by docket entry on January 16, 2026.

The City of Indianapolis provided testimony and attachments from Theodore J. Sommer, CPA, Sommer Consulting LLC.

On October 7, 2025, the IG filed the cross-answering testimony of Ms. York and the CAC filed the cross-answering testimony of Mr. Inskeep.

Also, on October 7, 2025, AES Indiana prefiled the rebuttal testimony, attachments and workpapers of:

- Brandi Davis-Handy;
- Chad A. Rogers, Director Regulatory Affairs Indiana, AES Indiana;
- Michael L. Holtsclaw;
- Gregory Ellis;

- David Faller;
- Adrien M. McKenzie;
- Dustin J. Illyes;
- Alexander J. Dickerson;
- Cody A. Flint;
- Natalie Herr Coklow, Senior Manager, Regulatory Accounting, AES Services;
- Pilar Cuadra, Environmental Manager, AES Global Environmental Affairs, AES Services;
- Matthew J. Dalton;
- Zac Elliot, Director, Customer Solutions, AES Services;
- Alan Felsenthal, Managing Director, PricewaterhouseCoopers LLP;
- Nicholas M. Miller;
- David Orr, Chief Digital Officer for US Utilities, AES Services;
- Steven Bramley, Customer Service and Back Office Manager for US Utilities, AES Services;
- Michael E. Russo;
- John J. Spanos;
- Paula M. Guletsky;
- Kimberly Aliff; and
- Bickey Rimal.

On October 15, 2025, AES Indiana, on behalf of itself, the IG, Walmart, Rolls-Royce, and the City of Indianapolis (collectively, “Settling Parties”), filed a Joint Motion for Leave to File Settlement Agreement and for Modification of Procedural Schedule (“Joint Motion”). The Joint Motion informed the Commission that the Settling Parties had executed the attached Stipulation and Settlement Agreement (“Settlement Agreement”), which resolved all issues pending before the Commission in this proceeding among the Settling Parties. The OUCC and CAC were not parties to the Settlement Agreement. On October 31, 2025, the Joint Motion was granted, and the procedural schedule was amended.

On October 21, 2025, the OUCC filed a Motion to Conduct Public Field Hearings concerning the proposed Settlement Agreement. AES Indiana filed its Response in Opposition to the OUCC’s Motion on October 24, 2025. On October 31, 2025, by docket entry, the Presiding Officers denied the OUCC’s Motion to Conduct Public Field Hearings.

On October 22, 2025, AES Indiana prefiled the settlement testimony and attachments of Mr. Elliot, Mr. Rogers, and Mr. Rimal. Contemporaneously, the IG prefiled the settlement testimonies of Ms. York and Mr. Gorman, and Walmart prefiled the settlement testimony of Mr. Lyon.

On November 6, 2025, AES Indiana responded to ex parte communications, which was tendered to the record on November 3, 2025. On November 3, 2025, AES Indiana filed a motion to strike portions of CAC’s cross-answering testimony (“Motion to Strike”). CAC filed its response to the Motion to Strike on November 13, 2025, and AES Indiana filed its reply on November 18, 2025. On November 21, 2025 by docket entry, the Presiding Officers took administrative notice

of AES Indiana's compliance filings in Cause No. 45911 dated September 30, 2025 and November 17, 2025.

On December 12, 2025, the OUCC prefiled the settlement opposition testimony and attachments of Ms. Baker, Mr. Courter, Mr. Deupree, Mr. Eckert, Mr. Garren, Mr. Kelley, Mr. Lantrip, Mr. Latham, and Ms. Sanka. Contemporaneously, CAC prefiled the settlement opposition testimony and attachments of Mr. Inskeep and Mr. Barnes.

On January 9, 2026, AES Indiana filed settlement rebuttal testimony of Mr. Rogers, Mr. Elliot, Mr. Flint, Mr. Holtsclaw, Mr. Spanos, Mr. McKenzie, Mr. Illyes, Mr. Bramley, Mr. Dickerson, Mr. Rimal, and Ms. Herr Coklow. On January 9, 2026, the IG filed settlement rebuttal testimony of Ms. York and Mr. Gorman. On January 9, 2026, AES Indiana filed a supplemental reply regarding its Motion to Strike and advised the Commission that Mr. Bramley's settlement rebuttal testimony responded to the cross-answering testimony, which was the subject of the Motion to Strike. Further, AES Indiana indicated it would withdraw the Motion to Strike if Mr. Bramley's settlement rebuttal testimony was admitted into evidence. As indicated below, Mr. Bramley's settlement rebuttal testimony was admitted into evidence, rendering the Motion to Strike withdrawn.

On January 16, 2026, the Commission issued a docket entry requesting additional information, which Petitioner responded to on January 21, 2026. On January 20, 2026, at 1:00 p.m. a virtual Attorney's Conference was held to discuss evidentiary hearing logistical matters.

On January 27, 2026, the Commission issued a docket entry requesting additional information, to which Petitioner responded on January 27, 2026. Also, on January 27, 2026, the OUCC filed its Motion to Strike Inappropriate Argument and Supplementation Filed as Petitioner's Response to the Commission's January 16, 2026, docket entry ("OUCC Motion to Strike"), to which Petitioner responded on January 28, 2026. At the hearing, the OUCC Motion to Strike was granted in part and denied in part.

The Commission conducted an evidentiary hearing in Room 222 of the PNC Center beginning at 10:30 a.m. on January 28, 2026, and continuing on January 29, 2026. AES Indiana, the OUCC, and the intervenors participated in the evidentiary hearing, by counsel, the parties' respective prefiled evidence was admitted into evidence.

Based upon the applicable law and evidence of record, the Commission finds:

1. Notice and Jurisdiction. Due, legal and timely notice of all public hearings in this Cause was 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 42.7 ("Section 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. AES Indiana’s Organization and Business. 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 Indiana provides retail electric utility service to approximately 532,000 retail customers located principally in and near Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam, and Shelby.

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. Existing Rates. AES Indiana’s current basic rates and charges were approved by the Commission in its Final Order in Cause No. 45911, based upon test year operating results for the 12 months ended December 31, 2022, adjusted for fixed, known, and measurable changes. The petition initiating Cause No. 45911 was filed with the Commission on June 28, 2023. Therefore, in accordance with Ind. Code § 8-1-2-42(a), at least 15 months have 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. Test Year and Rate Base Cutoff. As authorized by Ind. Code § 8-1-2-42.7(d), the forward-looking test period is the 12 months ending December 31, 2026 (“Test Year”). In accordance with Section 42.7, this Test Year (which commences January 1, 2026) begins not later than 24 months after the date on which the Petition was filed. The Test Year ending, December 31, 2026, is the general rate base cutoff date.

5. Relief Originally Requested by AES Indiana. In its Verified Petition, AES Indiana requested the Commission approve an overall annual incremental increase in revenues from basic rates and charges of approximately \$192.2 million. AES Indiana proposed to implement the requested revenue increase in two steps through a Phase-in-Rate Adjustment (“PRA”) process. In Phase I, revenue would increase by approximately \$85.4 million. Phase II would reflect an increase of \$107.5 million. A revenue increase of approximately 17% has already been authorized by the Commission for Petitioner’s Transmission, Distribution, and Storage System Improvement

Charge (“TDSIC”) Plan and other capital investment projects. The previously approved revenue increase is included in this filing. AES Indiana also requested Commission approval of specific accounting and ratemaking relief, including new depreciation accrual rates based on the Equal Life Group (“ELG”) procedure; deferrals and amortizations; vegetation management expense based on new competitively bid contracts, an extended trimming specification and other system needs; and rate adjustment mechanism proposals, including a new Property Tax Adjustment (“PTA”) rider; and approval of its proposed revenue allocation and rate design and new schedules of rates, rules and regulations for service. AES Indiana’s filing reflected annual investments of approximately \$953 million and \$957 million in the forecasts for 2025 and 2026, respectively. Approximately 66% of this investment was previously approved by the Commission. AES Indiana’s filing reflects a forecasted weighted average cost of capital (“WACC”) of 7.52% with a regulatory capital structure of 47.33% long-term debt and 46.48% common equity as of December 31, 2026, which includes Petitioner’s prepaid pension asset [net of the Other Post Employment Benefits (“OPEB”) liability] as a reduction to the zero-cost capital component of its ratemaking capital structure. AES Indiana’s proposed WACC reflects an increase in Petitioner’s currently authorized return on equity (“ROE”) of 9.9% to 10.7% based on the recommendation of its cost of equity (“COE”) expert and a COE range of 10.2% to 11.2%.

AES Indiana witness Handy explained that to manage the cost of providing service Petitioner uses the Integrated Resource Plan (“IRP”) process to identify the reasonable least cost mix of resources (referred to as a Preferred Portfolio) to meet the need for electricity within its service area. Petitioner also explained that it uses competitive solicitations and negotiations to safeguard the reasonableness of the cost of resource selected as a result of its IRP process. AES Indiana noted it has and continues to use investment tax credits and joint ventures to reduce the overall cost of new renewable resources for the benefit of AES Indiana’s customers. Petitioner explained that it considers affordability in the context of ratemaking constructs, cost causation and rate design. In particular, AES Indiana has and continues to use 100% of the off-system sales (“OSS”) margins generated in the competitive wholesale market to reduce the retail price for electricity. Petitioner’s proposed revenue requirement embeds an annual amount of \$24.9 million OSS margins as a credit to reduce the base price for retail electric service; and which it proposes to continue to adjust via the OSS Rider following this rate review. AES Indiana explained that its filing reflects the use of reasonable amortization periods to spread the recovery of certain costs over multiple years. As stated in Petitioner’s filing, AES Indiana employs reserve treatment for vegetation management expense and storm expense to safeguard against Petitioner spending less on those costs as compared to what was embedded in base rates. The balance of these reserves is to be trued up in the next rate case.

AES Indiana also states that it addresses affordability through other initiatives, such as Demand Side Management/Energy Efficiency (“DSM”), including a program targeted to low-income households. AES Indiana participates in customer assistance programs, such as the Energy Assistance Program (also referred to as Low-Income Energy Assistance Program or “LIHEAP”) and the Winter Assistance Program – which help low-income customers afford their energy bills, especially during the winter heating season. Petitioner’s Power of Change program also assists income-qualified customers with a one-time grant for electric bill assistance.

AES Indiana provides that it works individually with customers who fall behind on bill payments to work out a plan to get their account current, offers a preferred billing date if a particular time of the month is more convenient for a customer, and also offers budget billing to help reduce volatility in monthly bills. In this case, Petitioner proposes to maintain the customer support practices implemented as a result of the settlement approved in Cause No. 45911.

AES Indiana provides that to balance the interests of all customer classes, Petitioner's rate proposals rest on principles of cost causation as discussed by Mr. Rimal. Mr. Rimal explained that gradualism is another objective reflected in Petitioner's proposed rate design. AES Indiana considered affordability for each of the customer classes, and determined that the percentage rate increases experienced by individual rate schedules should be mitigated to moderate the impact on individual rate schedules.

AES Indiana also stated that it considered reliability, resiliency, stability and environmental sustainability in its ongoing investment in production plant, and transmission and distribution ("T&D") systems. Petitioner considered its proposals regarding vegetation management and storm restoration to be consistent with the Five Pillars of Indiana energy policy as set forth in Ind. Code § 8-1-2-0.6 (reliability, resiliency, stability, environmental sustainability, and affordability; collectively, "Five Pillars").

6. OUCC. The OUCC calculated a proposed revenue requirement, which supported a decrease in Petitioner's rates. Based on this calculation, the OUCC recommended the Commission order a \$21.2 million decrease from Petitioner's current rates. The OUCC's analysis reflected the following:

A. Depreciation. Mr. Garren recommended depreciation rates be based on the average life group ("ALG") technique. He also recommended the contingency factor for terminal retirement costs be 10% and Petitioner's proposed 2.5% per year escalation factor for terminal retirement costs be rejected. In addition, Mr. Garren recommended adjustments to service lives for four plant accounts (Account numbers 352, 354, 355, and 356). He recommended adjustments to net salvage percentages for specific plant accounts (Account Numbers 351, 352, 354, 355, 361, 362, 365, and 371). These proposals reduced Petitioner's forecasted depreciation expense by \$62.9 million.

B. ROE and Capital Structure. The OUCC recommended the Commission approve an 8.5% ROE based on Mr. Courter's recommended 9.0% ROE and a 50 basis point reduction, which was proposed by Mr. Latham. Mr. Courter used a Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") to estimate Petitioner's COE. His DCF model produced an 8.55% COE for AES Indiana. Mr. Courter's CAPM analysis produced a 7.73% to 9.27% COE for Petitioner. Mr. Courter testified that data on dividend yields, stock market valuations, inflation, and economic growth do not support a 10.7% ROE. Mr. Latham's recommendation for a 50 basis point reduction was independent of Mr. Courter's analysis. Of the proposed 50 basis point reduction, the OUCC recommended a 30 basis point reduction based on the OUCC's contention that Petitioner has been inattentive to the Affordability Pillar. The OUCC's recommended 50 basis point reduction to the ROE also included a 20 basis point reduction

attributable to billing system issues related to the implementation of its ACE billing system (“ACE Project”), and the resulting adverse impact on AES Indiana customers.

C. Test Year Revenue and Operating Expenses.

1. **Amortization Expense.** The OUCC recommended the Commission require AES Indiana to reduce its base rates to account for the end of the amortization of regulatory assets upon the amortization period expiring.

2. **Base Cost of Fuel.** The OUCC objected to Petitioner’s proposed increase in the base cost of fuel and recommended a lower base cost of fuel of \$0.042260. Mr. Eckert stated this will help alleviate the immediate financial burden on ratepayers while still allowing Petitioner to recover and collect actual fuel costs.

3. **Major Storm Reserve Amortization.** The OUCC recommended AES Indiana’s Adjustment OM 11, Major Storms account be decreased by an annual amount of \$1.477 million.

4. **Public Utility Fee.** The OUCC proposed the Commission use the IURC Fee rate of \$0.1456147 for the period covering July 1, 2025, instead of the new IURC Fee rate of \$0.1750 enacted by the Indiana General Assembly in 2025, to determine pro forma Public Utility fee expense for the 2026 Test Year because the rate is fixed, known, and measurable.

5. **Rate Case Expense.** The OUCC recommended the Commission order AES Indiana to share rate case expense equally between shareholders and ratepayers. The OUCC also proposed the Commission require AES Indiana to reconcile the “Other – (Additional Witness/Consulting Support/Postage)” category of rate case expense to the actual amount incurred as part of Petitioner’s post-order compliance filing.

6. **Test Year Sales Forecast.** The OUCC recommended forecasted test year residential sales be increased by 2,126.25 MWh to account for fewer losses associated with residential solar panel installations.

7. **Uncollectible Expense.** The OUCC opposed AES Indiana’s use of the ten-year average of uncollectible expense adjusted to remove the high and low amounts (2023 and 2020) to calculate the forecasted uncollectible expense percentage. The OUCC proposed to calculate the expense by removing three years (2023, 2021, and 2020) and thus proposed a downward adjustment to uncollectible expense of \$1.042 million in lieu of the utility’s proposed increase of \$848,000.

8. **Vacant Positions.** The OUCC proposed the Commission remove all vacant positions as of July 15, 2025, from the forecasted revenue requirement.

9. **Vegetation Management Expense.** The OUCC proposed forecasted distribution system vegetation management expense be maintained at the same level authorized in Cause No. 45911 and that the Commission approve Petitioner’s proposed forecasted transmission system vegetation management expense.

D. Forecasted Rate Base.

1. **Capital Forecast.** The OUCC recommended approximately \$27.6 million in forecasted T&D capital expenditures and \$750,000 in forecasted generation capital expenditures be removed from AES Indiana’s capital forecast. The OUCC also recommended \$8.95 million of capital improvements associated with digital and information technology programs be removed from Petitioner’s capital forecast in recognition of the problems with the ACE Project.

2. **Fuel Oil Inventory.** Mr. Eckert recommended a fuel oil inventory level of 800,128 gallons or \$1,703,801, which reflects a downward adjustment of \$425,608 to AES Indiana’s proposed downward adjustment of \$741,000.

3. **Riders.** The OUCC recommended an extension of the current agreement that allows the OUCC and intervenors to file testimony in Petitioner’s Fuel Adjustment Clause (“FAC”) 35 days after AES Indiana files its petition and testimony. The OUCC opposed AES Indiana’s request for a PTA rider.

4. **Cost of Service (“COS”) and Rate Design.**

a. **Revenue Allocation.** Mr. Deupree recommended the Commission adopt a revenue distribution allocation method based on his allocated cost of service study (“ACOSS”) results. Mr. Deupree testified AES Indiana’s ACOSS incorrectly classifies fixed costs associated with production plant assets as exclusively demand-related. He disagreed with Petitioner’s reliance on the results of its minimum system study (“MSS”) to classify a portion of its distribution plant assets as being customer-related because large customers with relatively higher load factors are favored over residential and small commercial customers with lower load factors. He recommended any rate increase to any single rate class be limited to no more than 1.15 times the overall system average increase. Mr. Deupree recommended that if a rate decrease is determined to be appropriate, the classes currently earning a relative rate of return of less than 0.90 receive a rate decrease equal to 50% of the overall system decrease, with the remainder being equally allocated among the remaining classes.

i. **Customer Charges.** The OUCC recommended denial of AES Indiana’s proposed increase to monthly customer charges for residential and small commercial customers and recommended a reduction in the current residential customer charge from \$17.00 per month to \$11.25 per month for a customer using more than 325 kWh per month, and a decrease from \$12.50 per month to \$8.25 per month for a customer using less than 325 kWh per month. He also recommended a reduction to the customer charges for SS customers and SH customers, depending on usage.

5. **Other Matters.** Mr. Eckert recommended AES Indiana continue to follow the storm reporting requirements agreed to in Cause No. 45911.

7. **IG.** Based on the IG's calculation of a proposed revenue requirement, the IG's witnesses presented testimony supporting a recommended revenue increase of \$57.355 million. The IG's analysis reflected the following:

A. **Depreciation.** The IG recommended depreciation rates be based on the ALG procedure. The IG recommended different survivor curves for certain steam production accounts, depreciation of the Harding Street Solar Farm in the same manner as other mass property accounts, removal of contingencies in the estimated demolition cost, and longer service lives for Accounts 353 and 365. The IG's proposed depreciation rates would reduce AES Indiana's proposed test year's depreciation expense by \$71.8 million.

B. **ROE and Capital Structure.** The IG recommended a ROE within a range of 9.10% to 9.90%. The IG proposed the removal of the prepaid pension asset and the OPEB liability from the ratemaking capital structure.

C. **Forecasted Test Year Revenue and Operating Expenses.**

1. **Forecasted Vegetation Management Expense.** The IG recommended a forecasted vegetation management expense that recognizes cost escalation and proposed a budget of \$31.871 million, which is Petitioner's 2024 actual expense with a 10% escalation rate for the Test Year.

2. **Major Storm Reserve Amortization.** The IG recommended the utility's Adjustment OM 11, Major Storms account, be decreased to remove the contingency costs for the April 2, 2025 storm, which totaled \$812,277.

D. **COS/Rate Design.**

1. **Revenue Allocation.** The IG recommended that the Indiana jurisdictional revenue requirement and any authorized revenue increase be allocated to customer classes based on the cost of providing service to each of the customer classes. While Ms. York recommended that AES Indiana continue to use the coincident peak ("CP") method of cost allocation for production investment, she testified the 4CP method is superior to the 12CP method in forming allocation factors, which reflect causes of the production capacity costs incurred to serve customers. Ms. York recommended an alternative approach to move toward meaningful reduction of the substantial interclass subsidies present in AES Indiana's current rates. Under this alternative approach, half of the difference between the requested and approved increase would be used to reduce the excess rate levels paid by the classes providing subsidies. After the subsidy reduction is accomplished, rates for all classes, including the residential class, would be reduced on a proportionate basis. Ms. York testified that under her recommended approach, no class would receive a dollar increase greater than proposed by AES Indiana, rates would move closer to cost of service, subsidies would be more measurably reduced versus Petitioner's proposal, and an increase in residential rates would be mitigated.

8. **CAC.** The CAC did not calculate a revenue requirement but offered testimony in support of the following recommendations:

First, Mr. Inskeep recommended the Commission open an investigation into AES Indiana's billing system issues and deny cost recovery related to Petitioner's ACE Project that was authorized in Cause No. 45911 ("ACE Project"). He testified that the ACE Project was deployed on November 6, 2023, and that many AES Indiana customers have since experienced numerous billing issues. Mr. Inskeep stated that between deployment and June 3, 2024, AES Indiana reported that 61,772 customers experienced a billing issue. He stated that significant billing issues due to the ACE Project are ongoing. Mr. Inskeep described problems that have developed with AES Indiana's autopay system, which has affected hundreds of customers and has caused overcharges. He detailed the difficulty that customers have experienced in attempting to get AES Indiana to rectify the erroneous charges in a timely manner. He has stated that it is unclear if Petitioner has corrected the issues with the autopay system. Mr. Inskeep recommended denial of cost recovery for the ACE Project based on AES Indiana's mismanagement.

Mr. Inskeep testified concerning the affordability crisis, citing the enactment of the Five Pillars, as well as Governor Braun's public statements prioritizing residential electric affordability. He stated that over 100 AES Indiana ratepayers spoke in opposition to the requested rate increase during the four public field hearings. Mr. Inskeep testified that affordability was a concern of most speakers. Among other evidence regarding affordability, Mr. Inskeep stated that AES Indiana residential bills for customers using 1,000 kWh monthly grew by 11.9% between July 2023 and July 2024 and another 12% from July 2024 to July 2025. He testified that AES Indiana's proposed bill increases would result in a bill for a 1,000 kWh monthly customer increasing by more than \$32 between May 2025 and January 2027. Mr. Inskeep recommended the Commission: find that the utility affordability crisis is harming AES Indiana ratepayers and that AES Indiana's proposed rates are not just, reasonable, or in the public interest; direct AES Indiana to adopt a security deposit cap of \$50 for non-LIHEAP residential customers who attest to having a household income below the statewide median household income for their households' size and \$25 for LIHEAP customers; pause residential disconnections for nonpayment for an additional one-year period, discontinue all disconnections for nonpayment for Medical Alert customers; eliminate the reconnection charge for residential customers resuming service after being disconnected for a delinquent bill; direct AES Indiana to automatically waive the first two late payment charges a residential customer gets over a 12-month rolling basis; and approve Mr. Inskeep's proposed Affordable Power Rider.

Mr. Inskeep recommended denial of implementation of Phase 2 rates due to AES Indiana's ambiguity concerning plans for network upgrades and for direct connect facilities associated with new data center projects. Regarding the cost of capital, Mr. Inskeep demonstrated that a reduction in ROE below AES Indiana's current authorized ROE of 9.9% would reduce the rate increase. He testified that lower ROEs have been approved in recent rate cases, and that a lower ROE is warranted in this proceeding due to existing affordability concerns within AES Indiana's service territory. He recommended denial of AES Indiana's requested revenue requirement increase and recommended that to the extent a revenue increase is approved, AES Indiana's authorized ROE should be reduced. He also recommended the Commission deny AES Indiana's request to include in the revenue requirement its 2025 rate case expense.

Mr. Inskeep recommended that actions be taken to protect residential ratepayers and that affordability be considered and addressed. He recommended a review of T&D capital investment, which have significantly increased over the past several years, a review of vegetation management expenses, coal ash cleanup costs, and depreciation and amortization expenses.

Mr. Inskeep expressed concerns with AES Indiana's proposal for revenue apportionment, which he testified would result in a rate increase of 13.45% for residential customers, among the customer classes with the largest percentage rate increase. He recommended that if the revenue increase is approved, AES Indiana's proposed revenue apportionment be denied, and instead the Commission should approve an apportionment in which residential customers do not receive a rate increase higher than the system average.

Mr. Barnes recommended that the current customer charges of \$12.50 per month for months in which a customer's usage is 325 kWh or less, and \$17.00 per month for months where the customer's usage is greater than 325 kWh for non-multi-family residential customers be retained. Mr. Barnes recommended the customer charge for multi-family residential customers should be set at a flat rate of \$11.00 per month to properly reflect the lower costs required to serve multi-family residential customers.

Mr. Barnes requested the Commission direct AES Indiana to conduct a more complete study of the differences in the costs of service for multi-family and non-multi-family residential customers for further consideration in its next general rate case. Mr. Barnes recommended the declining block design of residential rates be modified to reduce the differential between Block 1 and Block 2 by 5% and the differential between Block 2 and Block 3 by 10%.

9. City of Indianapolis. Mr. Sommer recommended that the AES Indiana cost of service methodology be based on 4CP. Mr. Sommer contended Petitioner's 12CP and Non-Coincident Peak ("NCP") cost of service methods unfairly allocates costs to the street lighting class; and improperly allocated operating and maintenance ("O&M") costs to the MU-1 rate, which minimizes savings from LED lighting conversion. Mr. Sommer also recommended the ALG method for depreciation be used, since the ELG method does not account for the differences in types of lighting. Additionally, Mr. Sommer recommended AES Indiana continue to record the installation of LED fixtures associated with the City of Indianapolis. He also recommended AES Indiana be required to complete the analyses it agreed to in Cause No. 45911. He recommended the Commission limit any increase to the street lighting class to the lesser of system average or the overall residential class increase. Mr. Sommer also recommended AES Indiana continue to replace its own obsolete lighting technology with LED lights and continue to work with area municipalities to assist them with their own lighting replacement.

10. Kroger. Mr. Bieber recommended modifications to AES Indiana's rate design for Rate SL to better align rates with the underlying cost. Specifically, he recommended setting the demand charge to \$31.37 per kW and setting the energy charge to \$0.058648 per kWh, at AES Indiana's proposed revenue requirement. Mr. Bieber testified that this recommended rate design aligns rates with the underlying cost components and proportionately splits Petitioner's proposed mitigation subsidy between the demand and energy charges. To the extent the Commission approves a revenue target for Rate SL that is different than that proposed by AES Indiana, Mr.

Bieber recommended that the demand charges and the energy charges he proposed each be reduced by an equal percentage to recover the target revenue requirement.

11. Walmart. Mr. Lyon recommended a close examination of AES Indiana’s proposed revenue requirement increase and the associated proposed increase in ROE. If Petitioner’s proposed revenue requirement is approved, Mr. Lyon testified that Walmart does not oppose AES Indiana’s revenue allocation proposal. Mr. Lyon testified that during 2023, 2024, and up until the filing of his testimony, the Commission issued orders with stated ROEs in six causes, with the average of the ROEs approved equal to 9.81%. Mr. Lyon testified that the range of reported authorized ROEs nationally for the recent period is 8.63% to 11.45%, and the median authorized ROE for all electric utilities is 9.70% and 9.77% for vertically integrated electric utilities.

Walmart advocated that rates be set based on AES Indiana’s cost of service for each rate class to produce equitable rates that reflect cost causation, send proper price signals, and minimize price distortions. If the Commission approves a lower revenue requirement for Petitioner, Mr. Lyon recommended the Commission increase the proposed increase cap factor above 1.3 times the overall system increase to further reduce subsidies while also ensuring that no class receives an increase greater than that proposed by AES Indiana. Walmart supports Petitioner’s decision to retire its existing self-supplied electric vehicle (“EV”) program and recommended that AES Indiana offer an EV tariff for third-party owned public direct current fast charging (“DCFC”) stations. Walmart recommended denial of AES Indiana’s request to recover additional costs through riders, and if not, the Commission should require a base rate case stay out.

12. Cross-Answering Testimony. CAC and the IG filed cross-answering testimony in support of recommendations summarized below.

A. CAC. Mr. Inskeep discussed the list of Commission Consumer Affairs Division (“CAD”) complaints included with OUCC testimony, testifying that he stood by his direct testimony recommendations. Mr. Inskeep discussed deficiencies and limitations of AES Indiana’s Root Cause Analysis (“RCA”). He responded to OUCC witness Latham’s recommendation for a 20 basis point reduction to AES Indiana’s authorized ROE and disagreed that this reduction is an adequate remedy. Mr. Inskeep recommended that OUCC witness Latham’s recommendation for a downward revision to the authorized ROE be considered in addition to his recommendations.

Mr. Inskeep disagreed with IG witness York’s proposed use of 4CP for production cost allocation. He also disagreed with City of Indianapolis witness Sommer’s testimony regarding the 4CP allocation method. Mr. Inskeep supported OUCC witness Deupree’s proposal to classify 70.36% of AES Indiana’s production plant costs as energy-related and 29.64% as being demand-related. Mr. Inskeep stated that if Mr. Deupree’s approach is rejected, then the 12CP method should be used and the 4CP method rejected. Mr. Inskeep also agreed with OUCC witness Deupree’s recommendation concerning distribution system classification.

B. IG. Ms. York explained that after reviewing OUCC witness Deupree’s direct testimony, she continues to support a coincident demand allocation of production and transmission investment cost in AES Indiana’s ACOSS. She stated that Mr. Deupree’s proposal is counter to previous findings of the Commission with respect to cost of service methodology. Ms.

York stated the Peak and Average (“P&A”) cost allocation method proposed by Mr. Deupree is not reasonable. She explained that this allocation method gives significant weight to annual energy consumption and lesser weight to the contribution to system peaks in allocating investment in production facilities. Ms. York stated that because generation facilities must be designed to meet peak demand loads, such an allocation factor results in a cost allocation that is not related to cost of service. She explained that the Commission has rejected similar OUCC arguments in previous cases, and Mr. Deupree has offered no new evidence to support his assertions in this case. Ms. York explained that the theory underlying Mr. Deupree’s position is outdated and the method is flawed. She explained that the Average and Excess method does not double count loads as is the case for the P&A method, which erroneously adds the entire average demand for a class to the entire peak demand for a class, ignoring that the average load is part of the peak load. Ms. York supported AES Indiana’s ACOSS use of minimum system technique to properly classify a portion of distribution costs as customer-related, particularly for distribution plant in FERC Accounts 364 through 368 and explained that multiple Indiana Investor-Owned Utilities (“IOUs”) used a minimum system technique. She supported her views with a discussion of the National Association of Regulatory Utility Commissioners (“NARUC”) Manual and other state commission precedent. She stated it is indisputable that a customer component exists in the classification of distribution system cost and recommended the Commission accept the minimum system approach in the allocation of distribution costs as proposed by AES Indiana in this proceeding.

Ms. York testified that Mr. Deupree’s recommendation that no class receive an increase of more than 1.15 times the overall system average (which is even more restrictive than the 1.3 times the overall system average that AES Indiana proposed) is arbitrary and an impediment to reducing the subsidization that continues to exist in current rates as calculated in AES Indiana’s filing and in her direct testimony.

Ms. York explained that Mr. Inskeep’s recommendation regarding apportionment ignores the COS, would further the subsidization in AES Indiana’s current rates, and would abandon the principle of cost-based rates. She testified that CAC’s proposal should not be adopted since it results in rates that do not reflect cost and distort price signals.

Ms. York also disagreed with Mr. Barnes’ assertion that distribution costs should not be classified, in part, as customer-related, explaining that there are clearly customer-related costs incurred in designing a distribution network, and allocating this portion of distribution costs using a customer classification is necessary in order for rates to adequately reflect cost-causation. She stated a customer classification of distribution costs is noted as reasonable by the NARUC Manual. Ms. York stated that if Mr. Barnes has an issue with AES Indiana’s proposed customer charges for the residential class, that is a rate design issue with residential rates in particular that should not and does not need to distort the ACOSS or the revenue allocation amongst customer classes. Ms. York recommended the Commission reject Mr. Barnes’ proposal regarding the classification and allocation of distribution system costs.

13. AES Indiana Rebuttal. In its rebuttal evidence, AES Indiana reduced the net operating income deficiency from \$192.9 million to \$182.7 million, which is an overall revenue increase of 9.8% rather than a 10.1% increase in overall retail revenues as filed initially. AES

Indiana's rebuttal filing also stated the extent to which Petitioner agreed or disagreed with the OUCC and Intervenors' positions as summarized below.

A. Affordability. Ms. Davis-Handy and Mr. Rogers disagreed with the OUCC's position that AES Indiana is indifferent to the affordability pillar. Ms. Davis-Handy stated that AES Indiana's filing demonstrates Petitioner's reasonable and sound management of costs despite inflation and growth in rate base. Mr. Rogers addressed each of the OUCC's claims, stating that AES Indiana's filing reasonably considers affordability of service with respect to present and future generations of Indiana citizens and is consistent with Ind. Code §§ 8-1-2-0.5 and -0.6.

Mr. Rogers stated that the operating expense test and the earnings test calculated quarterly in AES Indiana's FAC filings identify the extent to which utility investors are bearing the costs of providing service. He testified the most recent FAC operating expense test shows actual non-fuel operating expenses exceed the level of such operating expenses reflected in current rates by over \$131 million, and the most recent quarterly FAC earnings test shows Petitioner has cumulatively underearned its authorized return by nearly \$394 million over the past five years. Additionally, he testified that AES Indiana bears the risks of increases in costs not captured in the revenue requirement to determine basic rates.

Mr. Rogers testified that Mr. Latham's recommended 30 basis point downward adjustment to ROE is arbitrary. To put into perspective the financial impact of Mr. Latham's proposal, Mr. Rogers stated that a 30-basis point downward adjustment to ROE results in a decrease to annual allowable net operating income ("NOI") of approximately \$7.8 million yearly. Mr. Rogers recognized that the Commission has used the ROE number at the lower end of the reasonable ROE range to reflect the Commission's displeasure with a utility's management and to encourage improved performance in the future, and stated these decisions typically addressed safety and operational concerns. Mr. Rogers stated that Commission-awarded ROEs recognize the importance of assuring a utility can maintain its financial resilience.

Messrs. Illyes and McKenzie supported the need for AES Indiana to maintain adequate financial strength and to be able to afford a reasonable opportunity to earn a fair return. Mr. Elliot further responded to the OUCC and CAC testimony regarding affordability. He presented a "share of wallet" analysis showing that average, actual bills for AES Indiana's customers are in line with median income growth in Marion County, Indiana, and have been below cumulative inflation over the prior ten-year period of 2014 to 2024.

B. ACE Billing System Project. Ms. Davis-Handy acknowledged the billing issues stemming from the ACE Project and subsequent customer frustrations, but disagreed with CAC witness Inskeep's contention that AES Indiana has attempted to downplay the issues and has not been transparent. She testified that the billing system matters have been resolved and the associated cost of resolving these matters is not reflected in the Test Year in this Cause.

Messrs. Orr and Bramley addressed technical matters related to the ACE Project raised by the OUCC and CAC. Mr. Orr testified that Petitioner relied on the Accenture, who was contracted by AES Indiana to execute the ACE Project, Readiness Wheel showing a fully green status across all readiness categories to determine to go-live with the customer information system ("CIS")

billing system in Indiana and explained that Accenture is an industry recognized leader in SAP implementations. Mr. Orr disagreed that the system was prematurely placed into service, and emphasized that AES Indiana reasonably relied on Accenture's analysis in making the go-live decision.

Mr. Orr also opined that the OUCC's suggestion that the issues could have been resolved elsewhere had Indiana not been implemented first is not correct. He stated most billing issues in Indiana were related to bill print and bill presentment. He testified these code blocks are unique to each jurisdiction, and fixes to these issues would not benefit other jurisdictions. Mr. Orr discussed the numerous ways AES Indiana customers benefited from the shared development process, including reduced overall costs and reduced licensing and support costs.

Mr. Orr testified that the OUCC suggestion that AES Indiana did not hold the contractor accountable is incorrect. In response to OUCC witness Lantrip, Mr. Orr clarified that Petitioner did not need to seek reimbursement from the contractor because the resolution of issues occurred during a designated warranty period and thus all issue remediation was covered by the scope of this warranty. Mr. Orr added that during the warranty period, AES Indiana also undertook work that was outside the original project scope in order to improve the operational efficiency of the billing system, and that this work was performed by Accenture at discounted pricing, which helped mitigate the financial impact of these enhancements.

Mr. Orr disagreed with CAC witness Inskeep's contentions regarding the promptness of AES Indiana's response to the CIS issues. Mr. Orr testified that Petitioner acted promptly and diligently to resolve system issues to ensure the billing issues were resolved appropriately. Mr. Orr testified that the issues with the CIS billing system were remediated in August 2024. He stated that since then, the system has operated as intended to reliably produce invoices and support customer operations. He clarified that in the normal course of business; AES Indiana reasonably expects systems to require maintenance and improvements. He testified that it is standard practice to see higher levels of enhancement activities, change requests, and issue resolutions early in a platform's lifecycle as the system is used. Mr. Orr stated that to ensure ongoing reliable usage, Petitioner leverages system quality metrics to monitor the performance of the CIS billing system daily.

Mr. Orr disagreed with Mr. Inskeep's contention that AES Indiana has not been forthright in its compliance reports. He testified AES Indiana compiled data and other information responsive to the Commission's directive, including responses to the additional questions posed by the Commission and explanations of technical terms. Mr. Orr stated the billing system implementation was complex due to the integration with other systems, but this investment was necessary to replace legacy infrastructure dating back to 1996.

Mr. Bramley disagreed with the OUCC and CAC characterizations of the customer impacts of the billing system transition issues. Mr. Bramley testified that at its peak (in February and March 2024), the billing system transition issues impacted approximately 12% of customers; he added that the predominant issue customers experienced concerned Out-of-Balance bills, which were resolved or corrected in subsequent billing cycles. Mr. Bramley testified that the new billing system has issued millions of accurate and timely invoices. Mr. Bramley testified that AES Indiana undertook extensive outreach, including emails, letters, in-person events, media stories,

interviews, and outbound call campaigns to keep customers informed about CIS implementation and related developments. Mr. Bramley stated that while CAC witness Inskip referenced approximately 214,000 disconnection notices sent in the first six months of 2025, only 17,866 of these customers were disconnected for non-payment. He added that when a disconnection occurs, AES Indiana's remote reconnection capabilities enable a customer to reestablish service within minutes of making the required payment. He stated that as of September 30, 2025, the disconnect-to-reconnect ratio stood at 75%, indicating that most disconnected customers were reconnected promptly.

Mr. Bramley stated that the autopay issue, whereby customers were able to create duplicate autopay profiles by pressing the "Start AutoPay" button multiple times, was a 2024 payment vendor issue, not a CIS issue. He stated that AES Indiana worked with the vendor to resolve the issue and Petitioner worked with affected customers to issue refunds, including financial institution fees.

Mr. Bramley testified that AES Indiana makes every reasonable effort to ensure that supervisors are available to customers at the time a request is made. Further, he stated that during periods of unusually high call volumes or when demand for supervisory assistance exceeds available staffing, customers are offered the option to receive a callback within 24 hours. Mr. Bramley testified customers electing to remain on hold for the next available supervisor are advised that their wait times may be longer than expected due to these operational constraints.

Mr. Bramley testified that Mr. Inskip's testimony regarding collections omits a critical detail regarding AES Indiana's disconnection for non-payment procedures. Mr. Bramley testified that due to the suspension of disconnection activity during the CIS implementation period, only 3,710 accounts were sent to collections between November 2023 and April 2025. Further, he stated that, based on historical averages, AES Indiana would have expected to send approximately 35,449 accounts to collections over the same 18-month period without CIS implementation.

Messrs. Roger and Bramley stated that the CIS issues have been resolved, AES Indiana has already held itself accountable and the Commission continues to oversee these matters. Mr. Rogers presented a calculation of the economic impact Petitioner and its shareholders have already experienced related to the CIS billing system issues. This analysis reflected uncollectible accounts expense of approximately \$40 million in excess of what is included in base rates in 2024 and 2025, and estimated foregone late fees of approximately \$7 million in 2024 and 2025.

Mr. Rogers also testified that the CIS billing system portion of the ACE Project has an estimated utility plant in service net of accumulated depreciation (rate base) value of approximately \$40.7 million as of the end of the test year in this case. He explained that the impact to AES Indiana's return (NOI) on the CIS billing portion of the ACE Project being included in rate base is a \$3.1 million (using the full WACC) or \$2.0 million impact (using the equity portion of WACC). He testified that Mr. Latham's recommended 20-basis point reduction to ROE applied to all AES Indiana rate base would result in a reduction to its NOI of \$5.5 million. Mr. Rogers testified that Mr. Latham's suggested ROE reduction is not only unnecessary due to the financial impact Petitioner has already incurred related to this project but is also overly punitive as compared to the

NOI impact of the CIS billing portion of the ACE Project. He concluded that the severe financial penalties recommended by the OUCC and CAC should be rejected.

C. OUCC Revenue Requirement Correction. AES Indiana witness Aliff testified that the OUCC's revenue requirement calculation did not include an adjustment for the revenue impact of the OUCC's proposed change in the base cost of fuel. She asserted the OUCC's calculated revenue requirement is flawed because fuel costs are recovered 100% through the FAC, and total forecasted fuel revenue should match total forecasted fuel expense. She testified that the OUCC revenue requirement, if accurately calculated, would reflect a \$14.7 million increase in revenue as opposed to the \$21.3 million decrease described by OUCC witness Eckert.

D. Depreciation. Mr. Spanos responded to the testimony regarding depreciation filed by the City of Indianapolis, the OUCC and the IG. Mr. Spanos clarified the depreciation concepts underlying these issues.

1. ELG vs ALG Procedure. Mr. Spanos stated that the OUCC, the City of Indianapolis, and the IG proposed a change in depreciation expense compared to AES Indiana's proposal. He stated most of this difference is due to the use of different depreciation procedures. Mr. Spanos testified AES Indiana depreciation rates are based on the ELG procedure, which has been the leading procedure in Indiana for forty years.

Mr. Spanos testified that due to continual activity where assets are added and retired every year, ELG depreciation rates do not actually change as much as both witnesses claim. Based on his experience with utilities updating depreciation rates annually, Mr. Spanos testified that in actual practice, ELG depreciation rates are more stable than the other parties claim and do not warrant annual updating. Mr. Spanos stated that ELG is also discussed and supported in authoritative depreciation texts and academic literature.

Mr. Spanos testified that IG witness Andrew's proposal would result in unfairly pushing current customers' costs onto future customers. Mr. Spanos stated the use of ELG rates in the long run typically results in lower customer rates due to lower rate base, since ELG rates are usually higher than ALG rates. Mr. Spanos testified future customers will have to pay higher ALG depreciation rates than current customers as remaining life depreciation rates result in accumulated depreciation that will eventually revert to a lower level from the use of the ALG procedure. He explained that pushing costs into the future will create affordability issues for future customers. Mr. Spanos added that if the other parties' proposal to use ALG depreciation rates were adopted, then accumulated depreciation would be lower in the future. He explained that if, in the future, power plants (or any other asset) were retired earlier than expected, then more costs would have to be recovered in a short period of time.

Finally, Mr. Spanos explained that both OUCC witness Garren and IG witness Andrews did not accurately develop their 2026 forecasted book reserve, which is the basis of their development of depreciation expense for 2026.

2. Street Lighting and Signal Systems. Mr. Spanos testified that City of Indianapolis witness Mr. Sommer challenged the impact of the depreciation procedure on the identity of the assets within the two subaccounts of street lighting. Mr. Spanos clarified that neither depreciation procedure segregates the assets differently or mixes the recovery between the two subaccounts differently than the other. Ms. Spanos stated that the depreciation procedures recover the investment over the full-service life of the equipment within the account, adding that the ELG procedure accomplishes that consistent with how the assets are utilized while the ALG procedure averages all assets recovery regardless of whether they are in service for one year or more. Mr. Spanos testified that the assets in Account Number 373, includes the arms and poles for the lighting fixture which are the same for both older luminaries and LED.

3. Terminal Net Salvage/Decommissioning Costs. Mr. Spanos stated that OUCC witness Garren proposed two adjustments to the terminal net salvage estimates for AES Indiana's plants. Mr. Spanos testified the first is to remove the escalation component, which is used to estimate the cost to retire these facilities at the future date of their expected retirement (as opposed to in today's cost). He stated that escalation is necessary in order to recover the full net salvage costs of these facilities over their service lives. Mr. Spanos stated the second adjustment proposed by Mr. Garren is to reduce contingency from the decommissioning cost estimates to 10%.

Mr. Spanos testified the Commission has ruled that it is appropriate to include contingency in decommissioning estimates and that decommissioning estimates should be escalated to the date of retirement. Mr. Spanos clarified that IG witness Andrews did challenge the contingency component in decommissioning but did not challenge the 2.5% escalation component for decommissioning of generating facilities. He stated OUCC witness Garren proposed to arbitrarily reduce the contingency to 10% and proposed to eliminate the escalation factor.

In response to OUCC witness Garren, Ms. Guletsky testified that contingency factors are allowances included in a cost estimate to account for risks attributable to the maturity level of the source documents used to develop the estimate. She explained that contingencies were applied per industry standard and, disagreed with OUCC witness Garren contention that the contingency factor should be 5% to 10%. She testified the 5% to 10% range is for a detailed "Check Estimate or Bid/Tender," which is predicated on having a contractor bid in hand. She stated the estimates that have been prepared by S&L do not include this level of detail and are appropriate for the "Authorization or Control" level shown in the industry standards she provided.

Ms. Guletsky stated that the way contingency is calculated in the S&L analysis for individual components does not create excessive contingency costs as a percentage of total costs. She testified OUCC witness Garren's testimony does not recognize how the contingency is applied to the scrap value at each unit. She stated the scrap value contingency is a negative value, meaning the contractor cannot realize the full credit included in the cost estimate; therefore, the contingency on the scrap value increases the total cost of the project as well as the overall contingency applied.

She concluded that contingency is appropriate and a necessary component of the cost estimate; further, industry guidelines were followed to determine the appropriate level of contingency to set the decommissioning budgetary costs. Ms. Guletsky testified that the application of contingency serves to manage risk of overrun and, not eliminate risk in its entirety.

4. **Interim Survivor Curves.** Mr. Spanos testified that IG witness Andrews challenged the interim survivor curves for some generating accounts which affect the weighting of the net salvage for generating accounts. Mr. Spanos explained that the interim survivor curve must represent the age and percentage of assets that will be retired at each age interval. He stated IG witness Andrews' estimates do not realistically assess the level of retirements that will occur on an interim basis.

5. **Harding Street Solar.** Mr. Spanos testified that the next adjustment made by IG witness Andrews was his challenge to the life characteristics of the Harding Street Solar facility. Mr. Spanos testified IG witness Andrews proposed to remove the probable retirement component for solar generation assets. Mr. Spanos explained that, just like all other generating facilities, solar facilities will have periodic components of assets that will be retired and replaced annually, and will eventually have a concurrent date at which the facility will be retired. He testified that a solar facility cannot operate by retiring one panel at a time or one inverter at a time.

6. **Mass Property Service Lives.** Mr. Spanos testified that the next set of adjustments proposed by both IG witness Andrews and OUCC witness Garren were for the service life estimates for some transmission and distribution accounts. Mr. Spanos stated IG witness Andrews proposed longer service lives for one transmission and one distribution account while OUCC witness Garren also proposed longer service lives for four transmission accounts. Mr. Spanos stated each witness' proposals are based primarily, if not entirely, on comparing mathematical results from the statistical life analysis. Mr. Spanos testified that depreciation authorities, such as NARUC, include a subjective component in estimating service lives. Mr. Spanos stated that service life estimates are a forecast for the future and focusing only on mathematical calculations based on historical data will lead to unreasonable service life estimates.

7. **Mass Property Net Salvage.** Mr. Spanos stated the final set of adjustments proposed by OUCC witness was for changes to Mr. Spanos' net salvage estimates for some transmission and distribution accounts. Mr. Spanos testified OUCC witness Garren proposed changes to four transmission and four distribution accounts and, that OUCC witness Garren's adjustments do not follow a methodology that is supported by authoritative texts. Mr. Spanos explained that OUCC witness Garren's use of the last five years as a level for net salvage into the future understates the full-service value. Further, Mr. Spanos stated pushing the overall service value of existing assets into the future is not equitable to all customers. Mr. Spanos concluded that OUCC witness Garren's resulting proposal for net salvage appears arbitrary and lacks any basis beyond reducing the estimates proposed in the depreciation study.

Mr. Spanos added that the method of determining the net salvage estimates in the depreciation study should not only incorporate analysis of historical net salvage data, but also should include consideration of AES Indiana's operations and expectations for the future as well as trends in the electric utility industry. He testified these sources inform the judgment that is then used in determining a realistic estimate of the future net salvage, not an estimate that is selected only based on historical data.

E. Prepaid Pension Asset. Mr. Felsenthal testified that IG witness Gorman's proposal regarding the net prepaid pension asset balance would deny AES Indiana any return on the investor-sourced net prepaid pension asset. Mr. Felsenthal's testimony showed the buildup of the prepaid pension asset from its origination to December 2026 and supported that the source of the entire prepaid pension asset is investor capital which requires a return. Mr. Felsenthal testified that it is clear investors are the source of net prepaid pension asset and added that because the investor-supplied prepaid pension asset reduces pension expense (a direct benefit to customers) as well as provides employees the likelihood that amounts will be available to pay their retirement benefits, the utility is entitled to a return. Mr. Felsenthal explained that Mr. Gorman's proposal is counter to previous Commission decisions on this issue, and counter to fundamental ratemaking principles. Mr. Felsenthal added that Mr. Gorman recommended removing the prepaid pension asset from the capital structure but left the related prepaid pension asset accumulated deferred income tax ("ADIT") in the capital structure at zero cost and explained that this is an inconsistent and incorrect result.

F. ROE and Capital Structure. In response to IG witness Gorman and OUCG witness Latham, Mr. Illyes addressed changes to AES Indiana's cost of debt since filing of the case-in-chief that results in a four basis point decrease and a \$0.6 million reduction to Petitioner's overall revenue requirement.

In response to OUCG witness Latham, Mr. Illyes testified that AES Indiana's targeted capital structure seeks to improve its credit quality by reducing leverage to levels better in line with industry standards and Indiana IOUs. He added that the targeted capital structure would still leave AES Indiana with the lowest equity layer among Indiana IOUs. Mr. Illyes explained that, all things being equal, the additional costs seen from an increased equity layer would be partially offset by a reduced cost of debt, due to the resulting improvement in AES Indiana's credit metrics from the lower leverage and corresponding improvement in its credit ratings. He testified that ratepayers benefit from the proposed capital structure, as the increased equity component leads to a reduction in leverage which improves the financial integrity of Petitioner, making it better positioned to support service, reliability and continuous improvement with the ability to attract quality capital at a reasonable cost for the benefit of customers.

With respect to benefits, Mr. Illyes further explained that rating agencies evaluate capital structures qualitatively through their evaluation of the overall regulatory environment, judging predictability, full and timely cost recovery, and a regulatory environment supportive of an utility's financial integrity compared to other states and the consistency that orders are issued across their jurisdiction, including the approval of a fair capital structure. He stated utilities are evaluated quantitatively through their financial metrics, of which capital structure is a major factor. Mr. Illyes explained that being overleveraged compared to AES Indiana's peers negatively affects these calculations, reducing AES Indiana's overall credit metrics and resulting in lower credit ratings.

Mr. Illyes testified that OUCG witness Latham failed to consider how a downward adjustment to OUCG witness Courter's ROE would impact AES Indiana's credit ratings, which could impact the cost of debt and the WACC. He stated that a downgrade from the rating agencies could lead to an increase in AES Indiana's borrowing cost for its short-term debt, since Petitioner's revolving credit facility is tied to its credit ratings. He testified the lower credit ratings would lead

to a higher cost of debt, increasing the overall WACC of AES Indiana, which could negatively impact customers.

Mr. Illyes testified that lower credit ratings could impact AES Indiana's ability to access capital markets, which could impair Petitioner's ability to deliver service at a reasonable cost to customers. Mr. Illyes stated that maintaining a solid investment grade profile is important to ensure AES Indiana has reliable access to the credit markets at attractive interest rates during all types of economic cycles and added that AES Indiana has future capital expenditures related to ongoing investments to maintain and improve the utility systems that require access to capital markets on a regular basis.

Mr. Illyes testified that rejecting a fair return on equity could hinder AES Indiana's ability to attract capital needed for continued investments. Messrs. Illyes and McKenzie testified that the below market OUCC ROE recommendation of 9.00% with an additional 0.50% reduction, resulting in an 8.50% ROE, would signal a negative shift in Indiana's regulatory environment by both the credit rating agencies and the capital markets. Mr. Illyes added that an 8.50% ROE would represent a fundamental shift in underlying investment decisions, which has led AES to invest in AES Indiana and Indiana for the benefit of customers. He testified this shift would risk the ability of AES Indiana to attract both the equity and debt capital necessary to make the investments needed for Petitioner to continue to provide safe and reliable service at a reasonable cost, while supporting economic development for the benefit of customers and community.

Mr. Illyes testified the utilities are evaluated quantitatively through financial metrics, of which ROE is a major factor and explained that a higher ROE leads to greater cashflow, which in turn improves the overall credit metrics of AES Indiana and leads to higher credit ratings. He stated higher credit ratings result in a lower cost of debt and overall WACC, which benefits customers.

Mr. Illyes testified that even with the correction to its revenue requirement calculation presented by Ms. Aliff, the OUCC's recommended result would impair AES Indiana's ongoing operation and ability to make investments at a reasonable cost. He concluded that the recommendations put forth by the OUCC could harm ratepayers, as it would drive up the cost of debt and decrease investment appetite for utilities across Indiana.

Mr. McKenzie discussed the opposing witnesses' ROE recommendations, and presented comparable ROE benchmarks that provide a basis to gauge the reasonableness of the recommendations. Mr. McKenzie testified the opposing witnesses' ROE recommendations fall below the national average authorized ROEs, once adjusted for current interest rates. Mr. McKenzie testified that this ROE disparity is even more evident when considering that utility bond yields remain elevated since an ROE of 9.90% was approved for AES Indiana.

Mr. McKenzie stated the recommended ROE by opposing witnesses is inconsistent with economic reasoning, given that capital costs have increased. He stated consideration of current interest rates and allowed ROEs for other electric utilities demonstrate that the ROE recommendations of the opposing witnesses are too low.

Mr. McKenzie added that objective indicators of capital costs support the view that recently allowed ROEs nationwide and in Indiana have not kept pace with the upward move in capital costs that began in 2022. He stated capital costs have not declined since April 2024 when AES Indiana's current ROE of 9.90% was established. He stated it is inconceivable that AES Indiana's ROE could have fallen 65 basis points to an average ROE of 9.25% over a period when capital costs have remained elevated. He testified that the recommended decrease in AES Indiana's ROE does not follow the fundamental principles of finance since capital costs have increased.

Mr. McKenzie explained that adjusting national average allowed ROEs for 2020-2025 to account for the recent rise in bond yields implies a current cost of equity of 10.38%. He added that ROEs during times of comparable bond yields implies a current cost of equity of 10.33%. Mr. McKenzie explained that expected earned returns for the utilities in the opposing witnesses' proxy groups suggest an ROE in range of 11.0 to 11.1% for AES Indiana.

Mr. McKenzie testified that numerous flaws undermine the ROE analyses of the opposing witnesses, including: their reliance on a range of data that fails to reflect investors' expectations and current capital market conditions; their application of financial models in a manner that is inconsistent with their underlying assumptions; the failure to evaluate model inputs and exclude illogical results; and the application of CAPM that fail to capture a realistic appraisal of investors' forward-looking expectations and ignore the implications of firm size, which biases the resulting cost of equity estimates downward. Mr. McKenzie also stated the most recent long-term consensus projections from top economists published by Blue Chip document that bond yields are expected to remain elevated when compared to recent historical levels.

Mr. McKenzie testified that there is no basis to assume that investors reference long-term forecasts of Gross Domestic Product in developing their expectations for utilities. He explained that there is no basis for the suggestion that regulatory mechanisms approved for AES Indiana or its use of a forward test year differentiate AES Indiana's risks from the proxy utilities.

Finally, Mr. McKenzie discussed the ROE comments of Walmart witness Lyon, CAC witness Inskeep, and OUCC witness Latham. Mr. McKenzie stated that comparisons of permitted ROEs are just one factor and added that while this data can be useful in the Commission's deliberations, it is not a substitute for the detailed analyses presented in his direct testimony. He added that historical average ROEs do not reflect current capital market conditions. Mr. McKenzie stated Walmart witness Lyon wrongly suggested that a lower ROE is to the customers' benefit. Mr. McKenzie explained that while a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can work to the disadvantage of customers and the Indiana economy. Mr. McKenzie explained that the ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. Mr. McKenzie added that while AES Indiana would undoubtedly continue to meet its service obligations to customers, a downward-biased ROE would send a signal to the investment community.

Mr. McKenzie stated CAC witness Inskeep's and OUCC witness Latham's recommendation that the Commission significantly reduce AES Indiana's ROE is unsupported by evidence. Mr. McKenzie explained that taken as a whole, the opposing witnesses' recommended

ROEs fall below a fair and reasonable level for AES Indiana. Finally, Mr. McKenzie explained that the opposing witnesses' criticisms of his size adjustment, market return calculation, Empirical CAPM ("ECAPM"), risk premium method, expected earnings approach, and non-utility DCF analysis are without merit.

G. Test Year Revenue and Operating Expenses.

1. Amortization Expense. Ms. Aliff testified that reducing base rates to account for the end of amortization is not sound ratemaking practice and stated that there are no other expenses used in calculating base rates that are adjusted between rate cases. She explained that AES Indiana's proposed three-year amortization period is reasonably aligned with the period the rates established in this Cause are expected to be in effect.

2. Base Cost of Fuel and FAC Procedure. Mr. Dickerson testified that AES Indiana accepted OUCC witness Eckert's recommendation to continue the current FAC procedural agreement. Mr. Dickerson disagreed with OUCC witness Eckert's recommendation regarding the base cost of fuel, explaining that Mr. Eckert's proposal is not consistent with AES Indiana's forward-looking, data-driven fuel projection which is based on actual market conditions, contractual obligations, and operational realities. Mr. Dickerson explained that Petitioner's methodology is intended to create a stable base cost of fuel for customers and added that AES Indiana's fuel cost forecasting and dispatch modeling approach has been consistently accepted by the Commission and stakeholders as reasonable and reliable. Mr. Dickerson testified that setting the base cost of fuel using a different methodology creates a mismatch in the FAC forecasting process, leading to potentially greater volatility in the FAC rider rates and would mark a departure from the current method Indiana electric utilities follow. Mr. Dickerson explained that OUCC witness Eckert's assertion that AES Indiana's base cost of fuel would be the highest in Indiana does not account for the unique generation mix and infrastructure investments that differentiate AES Indiana's service territory and also does not consider timing differences as each utility's base cost of fuel gets updated through rate case filings. He stated that the OUCC's proposal would make future comparisons between utilities less meaningful as AES Indiana's base cost of fuel would be calculated differently than the other Indiana IOUs.

3. Major Storm Reserve. Ms. Coklow explained that Petitioner discussed the accounting for the Major Storm reserve and showed AES Indiana correctly reflected the Major Storm Reserve mechanism in its filing. She explained that the \$6.1 million liability included in AES Indiana's previous rate case was never moved from the balance of the Major Storm reserve and thus OUCC witness Lantrip's discussion mischaracterizes the reserve and fails to recognize that the \$6.1 million credit is still in the reserve account and is slowly being wound down, consistent with the accounting approved in Cause No. 45911. She testified that the \$4.431 million downward adjustment proposed by OUCC witness Lantrip does not reflect the full scope of major storm costs incurred by AES Indiana in 2025 or the 2025-2026 portion of the \$6.1 million credit included in this case and would result in delayed recovery of these costs and a higher balance to collect in a future rate case. She concluded that there should not be an additional \$2.03 million credit to the major storm reserve account included in the revenue requirement in this proceeding. She also concluded that the forecasted costs for the April 2025 storm should be included in the

revenue requirement in this case as actual costs for 2025 major storms are higher than the forecast included in this case.

Mr. Holtsclaw responded to IG witness Gorman's recommendation to remove contingency costs for the April 2, 2025 storm. Mr. Holtsclaw explained that the contingency line in the workpaper represents an estimated cost of storm restoration work that was performed but not yet invoiced. He testified AES Indiana is still waiting on final invoices but estimated the total cost of the April 2, 2025 storm to be \$5 million, which was the amount included in this Cause. Mr. Holtsclaw stated that actual storm costs in 2025 have exceeded \$5 million, which makes Mr. Gorman's concern moot.

4. Public Utility Fee. In response to the OUCC proposal regarding the public utility fee, Ms. Coklow explained that House Enrolled Act 1001 (2025), signed into law on May 6, 2025, modified Ind. Code § 8-1-6-4 with a retroactive effect of January 1, 2025 to change the public utility fee from 0.15% to 0.175%. She added that it is a reasonable assumption that the public utility fee will reflect the currently effective statutory rate for the 12-month period ending December 31, 2026.

5. Rate Case Expense. Ms. Aliff updated AES Indiana's rate case expense projection consistent with Petitioner's practice in its recent rate cases. Ms. Aliff's update showed the "Other" category questioned by OUCC witness Baker decreased from \$1.5 million to \$0.5 million, and total forecasted rate case costs decreased from \$4.5 million to \$3.2 million. Ms. Aliff stated Ms. Baker's recommendation that AES Indiana provide a final accounting of "Other" rate case expenses in its compliance filing is contrary to prior practice and unnecessary considering the decreased rate case expense presented in rebuttal.

Ms. Aliff explained that the OUCC position on sharing of rate case expense runs contrary to Commission practice and would result in treatment for AES Indiana that is different from other large public utilities in the state. Ms. Aliff also explained that CAC witness Inskeep's position that rate case expense should be wholly disallowed is inconsistent with decades of Commission precedent allowing recovery of such costs. She testified that Petitioner's current rate case expense closely aligns with the rate case expense from its most recent basic rate case and compares favorably to past basic rate cases despite the added complexity of this case. Ms. Aliff testified that CAC witness Inskeep cited no Commission precedent to support his position that rate case expense should be disallowed because the previous case expense has not yet been fully amortized and that the continued amortization of unrecovered rate case expense is consistent with past practice. She testified that AES Indiana met the Commission's standard for recovery of rate case expense, and it should be recovered as other costs that are reasonably incurred to comply with utility regulation.

6. Test Year Sales Forecast. Mr. Russo testified that OUCC witness Leader's recommendation to increase the 2026 test-year sales by 2,126 MWh is based on a subjective 25% reduction factor and does not consider the offsetting impact of changes to the electric vehicles forecast. Mr. Russo added that the OUCC's adjustment represents only a 0.039% increase in test-year MWh and added that any factor that changes the price of a good or technology will impact consumers' likelihood of purchase. Mr. Russo testified there is uncertainty about the future of the solar and EV market, but the impact of these recent changes is difficult to quantify in

an objective manner. He concluded that AES Indiana's forecasted test-year sales should not be changed.

7. **Uncollectible Expense.** Ms. Coklow testified that Petitioner's methodology for calculating uncollectible expense is consistent with the settlement agreements approved by the Commission in Cause Nos. 45029, 45911 and 44576. She testified that OUCC witness Eckert's proposal ignores the fact that the historical uncollectible account percentages have been trending upward since 2021. She testified that AES Indiana's approach maintains a consistent methodology and provides a balanced and reasonable method for forecasting uncollectible account expense by ensuring both high and low outliers are addressed without selectively removing recent data that reflects current trends and recommended using AES Indiana's proposed uncollectible expense percentage.

8. **Vacant Positions.** Mr. Dalton refuted the OUCC's characterization of the vacant positions as "phantom" employees or hires. He stated the vacant positions AES Indiana included in this case are actual positions, with associated job postings, active job searches, interviews, and pending job offers. Mr. Dalton stated that OUCC witness Baker did not identify a single position that she claimed was unnecessary or should not be filled. He stated that AES Indiana is working to fill all these positions to meet Test Year operating needs. Mr. Dalton testified that the OUCC's testimony does not accurately reflect the record in Cause No. 45911. He testified that 73 of the 115 positions Ms. Baker testified were vacant as of July 15, 2025 have since been filled. He added that the nine customer-facing positions mentioned by OUCC witnesses Baker and Lantrip were filled by mid-August. Of the remaining 42 positions, he stated 26 have open requisitions and hiring managers are in the process of conducting interviews with candidates. For the remaining 16, he stated AES Indiana intends to actively source the currently posted positions until they are filled and discussed Petitioner efforts to fill vacant positions. Mr. Dalton presented an analysis of AES Indiana's historical vacancy rates over the last five years. Based on this adjusted analysis, AES Indiana proposed a reduction to labor, benefits, and payroll taxes of \$3.4 million. Mr. Dalton stated this is a reasonable reduction based on a measurable average historical vacancy rate and is consistent with the Commission's recent handling of vacant positions.

9. **Vegetation Management.** Mr. Flint testified that the cost of vegetation management is primarily driven by market conditions for high-quality line clearance arborists and is based on competitively bid and negotiated contracts. He testified that comparing AES Indiana's proposed vegetation management expense in this case to the vegetation management expense approved in Petitioner's last rate case fails to consider numerous factors, including market-driven changes in vendor contract rates, labor market pressures, enhanced safety and compliance standards, and general inflationary cost pressure and also does not consider the change in trimming specifications and associated customer benefits. Mr. Flint disagreed with OUCC witness Sanka's testimony regarding AES Indiana's analysis of the benefits of extended trimming over the historical box cut approach. Mr. Flint testified that AES Indiana has been incrementally testing and verifying the benefits associated with extended trimming based on real-world data using AES Indiana's actual distribution circuits. He recognized that the character of data AES Indiana has collected to date is not the data OUCC witness Sanka prefers, but the results Petitioner sees justify continued use of the extended trimming specification. Mr. Flint explained that AES Indiana has taken a conservative approach to extrapolating systemwide benefits; its goal

is not to overstate customer benefits, but rather to responsibly scale a program that has demonstrated value. Mr. Flint responded to OUCC witness Sanka's criticisms in detail and disagreed that AES Indiana is not managing its vegetation management expense efficiently. He explained that vegetation management directly impacts system reliability, and underspending can lead to increased outages, safety risks, and long-term operational costs. He explained that if the OUCC's proposal was implemented, AES Indiana would need to revise its cycle length and allocation of funds for distribution trimming. He stated that the lack of increased funding would result in a significant reduction in the number of miles trimmed each year, which would extend the trimming cycle to approximately eight years—a duration longer than AES Indiana would consider acceptable. He added that extending the cycle length would also lead to more reactive work required under reliability trimming, and would create a much riskier environment for contractors and linemen.

Mr. Flint stated AES Indiana appreciates IG witness Gorman's willingness to address the role that inflation has played in the increasing costs of vegetation management for AES Indiana but added that his approach would leave AES Indiana facing a 6.5-year trimming cycle, which exceeds the utility's goal for vegetation management and could lead to increased future costs.

Mr. Flint testified that the assertion that AES Indiana has not provided evidence of a need to improve service reliability overlooks the role of proactive system management and the strategic use of reliability metrics. He testified indicators such as the System Average Interruption Duration Index, System Average Interruption Frequency Index, Customer Interruptions, and Customer Minutes Interrupted indices are influenced by multiple factors, including vegetation-related outages, which remain a significant contributor to service interruptions across AES Indiana's distribution system. Mr. Flint presented data that highlights the need for continued spending on vegetation management and the importance of increasing that spending as proposed by AES Indiana. Mr. Flint stated that the costs reflect actual rates AES Indiana has negotiated and that extending the trim cycle will improve reliability. Mr. Flint also responded to IG witness Gorman's criticisms of AES Indiana's analysis and disagreed with his contention that there is reason to believe AES Indiana will not spend its forecasted vegetation management expense. Mr. Flint stated IG witness Gorman's proposed transmission and distribution vegetation management expense of \$31.871 million would not allow AES Indiana to fully implement the five-year cycle using the extended trimming specification as outlined in his direct testimony and would undermine the reliability and safety improvements the extended specifications are designed to achieve.

Mr. Flint testified that CAC witness Inskeep did not identify any vegetation management expense that is unreasonable, nor did he provide evidence that refutes the reliability and customer benefits from extended trimming identified in Mr. Flint's direct testimony. With respect to affordability, Mr. Flint discussed Petitioner's effort to mitigate cost impacts and stated that given the importance of vegetation management to maintaining system reliability, AES Indiana's proposal reasonably balances the concerns of CAC witness Inskeep. Finally, Mr. Flint noted that, as discussed in Ms. Aliff's direct testimony, Petitioner's proposed continued use of the Vegetation Management Reserve ("Reserve") protects customers by serving as a cap on vegetation management expenses.

H. Rate Base.

1. Capital Forecast.

a. **Production Plant.** Mr. Ellis discussed the need at times to prioritize work and delay or cancel projects to redeploy funding committed from one project to higher priority, emergent projects and AES Indiana's efforts to work within its capital budget in total each year. Mr. Ellis supported the redeployment of forecasted capital from the cancelled Harding Street Station Wi-Fi Expansion project to two emergent projects: a fire system at Harding Street Station, which had recently developed several leaks in the underground piping throughout the facility and the replacement of the acid injection system for Harding Street Station's Unit 7 cooling towers, which maintains the pH of the cooling water used throughout Unit 7 and is critical to unit reliability. Mr. Ellis recommended that the redeployment of forecasted capital investment be approved despite OUCC opposition.

b. **Transmission & Distribution.** Mr. Faller responded to OUCC witness Kelley's testimony regarding accounting for transformers and testified that the way Petitioner accounts for transformers is consistent with FERC guidance, and that there is no potential for double recovery. Mr. Faller stated that the amounts identified by the OUCC are appropriately included in this filing.

Mr. Holtsclaw testified that AES Indiana has not been notified by the developer that the Indy Eleven Ph. 1 Stadium project has been cancelled and thus disagreed with the OUCC's proposal to reduce the capital forecast by the amount of this project. He added that if the stadium project moves forward the Test Year capital forecast will align with Test Year rates, which is the purpose of using a forward-looking test period. He stated that if the project is not completed by Test Year end, then it will not be included in rate base due to the true up mechanism presented in the direct testimony of Ms. Aliff.

Mr. Holtsclaw also disagreed with the OUCC's proposal to remove certain costs associated with corporate furniture expense from the forecast. He explained that the 2025 and 2026 projects include new office furniture for office moves and replacing obsolete furniture and stated the forecasted costs are reasonable and in line with historical spending.

Mr. Holtsclaw testified that the Monrovia Battery Energy Storage System land purchase would be addressed as necessary through the Test Year end rate base true-up mechanism sponsored by Ms. Aliff.

Mr. Holtsclaw also disagreed with OUCC witness Kelley that capital costs associated with new reclosers added to the system outside of Petitioner's TDSIC Plan should be removed from the capital forecast. Mr. Holtsclaw stated he disagreed with OUCC witness Kelley's contention that including these costs in the forecast would disincentivize AES Indiana to seek warranty replacements from the manufacturers. Mr. Holtsclaw explained that the budgeted capital costs assume warranty replacements by the manufacturers when applicable and that the remaining replacement costs that are not covered by the manufacturer's warranty.

Finally, Mr. Holtsclaw disagreed with Mr. Kelley's proposal to reduce the capital forecast by an amount equal to four additional projects. Mr. Holtsclaw explained that the amounts initially forecasted for the VW Electric Vehicle Fast Charging Project were reallocated to the IndyGo Blue Line project. With respect to the PMAC Display Software License project, Mr. Holtsclaw stated discovery responses inadvertently reported this project as cancelled but the project had been moved from 2025 to 2026 and is anticipated to be in service by the end of the 2026 Test Year. He stated the costs initially budgeted for the remaining two projects were reallocated to the new Indiana Fever Practice Facilities, Capital Tools and Equipment, and IndyGo Blue Line projects. Mr. Holtsclaw recommended all the forecasted costs remain in the Test Year subject to the Test Year end true-up presented by Ms. Aliff.

c. **Digital Improvements.** Mr. Orr explained that the \$8.95 million of capital improvements mentioned by OUCC witness Lantrip are not related to the issues that arose with the new billing system issues, which were remediated. He explained that this is a capital investment in a new Interactive Voice Response ("IVR")/Telephony system, which supports AES Indiana's call center operations and provides customers with self service capabilities to pay bills, request bill plans, request services, and report outages. Mr. Orr testified that the IVR/Telephony System is a key technical capability, which allows customers' needs to be met quickly. Mr. Orr explained that AES Indiana's existing IVR/Telephony system is no longer supported by the original vendor and the advanced age of the underlying hardware puts it at a higher risk of failure. He testified the new IVR/Telephony solution will remove this risk, ensure customers continue to have these key self-service capabilities, and provide a foundation to expand the self-service offering beyond what is provided by the existing IVR/Telephony system.

Mr. Orr testified that AES Indiana's existing website was initially placed in service in 2014. He stated the Website/IT Design investment is necessary to modernize online customer contact and self-service channels. He testified this will enhance operations and provide other benefits.

Mr. Orr explained that the CIS enhancements questioned by witness Lantrip are part of the natural evolution of the CIS platform as AES Indiana continues to focus on optimizing technology platforms in support of customers. Messrs. Orr and Bramley explained that at its peak, the ACE Project transition issues impacted approximately 12% of customers and were remediated by August 2024. Mr. Orr testified that the majority of AES Indiana's customers saw no adverse impact.

d. **Fuel Oil Inventory.** Mr. Dickerson explained that AES Indiana agreed with OUCC witness Eckert's recommendation of adopting a fuel oil inventory level of 800,128 gallons but stated that the correct value of the updated inventory balance would be \$1,703,799, not \$1,703,801 as reflected in OUCC witness Eckert's testimony.

2. **Riders.** Ms. Aliff explained why she disagreed with Walmart witness Lyon's position regarding the elimination of riders. Mr. Miller explained how property tax expense is subject to significant variability in annual tax assessments and added that the cause of the variability is generally due to factors outside of Petitioner's control and therefore results in significant uncertainty in forecasting property tax expenses in the future Test Year in this

proceeding. Mr. Miller’s rebuttal testimony outlined the ways in which the PTA rider would benefit customers.

I. COSS/Rate Design. Mr. Rogers explained that Mr. Rimal’s COSS show that commercial and industrial (“C&I”) customers have been subsidizing residential customers. Mr. Rimal recommended that this subsidy be reduced, which is consistent with the principle of cost causation. Mr. Rogers testified that AES Indiana has sought to reduce the subsidy provided to the residential customer class by other customer classes in each of its three most recent rates cases and is attempting to do so in this Cause.

Mr. Rimal responded to OUCG witness Deupree, IG witness York and CAC witness Barnes as summarized by topic below:

1. Demand-Related Production Cost. Mr. Rimal testified that he classified costs associated with production plant as being demand-related and used the FERC 12CP method to allocate these costs to the various rate classes. Mr. Rimal explained why he disagreed with OUCG witness Deupree’s concerns with this classification. He testified once installed and part of the utility’s overall portfolio, any generation asset is available for dispatch at any time. He added that the production plant costs are fixed in nature and do not vary with the amount of energy generated. Mr. Rimal stated the demand classification method used recognizes that the utility may call on any of the resources during the peak periods. He testified the CP method provides incentive for customers to improve their load factor, which is a desirable outcome. Mr. Rimal explained that the classification of fixed production plant as demand is based on cost causation and encourages efficient utilization of the system and stated this practice should be continued. He testified AES Indiana has consistently used this same classification and allocation method at least since 1994, if not before. He testified that all Indiana IOUs classify production plant as entirely demand-related and it has been a Commission practice to approve such classification.

Mr. Rimal noted that IG witness York stated that the CP method of cost allocation continues to be the most appropriate method of allocating AES Indiana’s investment in production facilities but claimed that 4CP is superior to 12 CP. Mr. Rimal disagreed with Ms. York’s concerns regarding the FERC tests and results. Mr. Rimal stated that the Commission has relied on the results of the FERC tests. Mr. Rimal testified that AES Indiana schedules its maintenance during the off-peak and shoulder months and added that the system capacity reserve often is not much different in the off-peak and shoulder months than it is in the peak months.

Mr. Rimal testified City of Indianapolis witness Sommer recommended that AES Indiana’s cost of service methodology be based on 4CP because it better reflects the lighting class demand on the system. Mr. Rimal disagreed, explaining that if the contribution to the monthly peaks by the lighting class goes down as a result of LED lights, 12CP would capture such reduction. Mr. Rimal stated Mr. Sommer has not provided any evidence suggesting why a 4CP allocator is better than a 12CP allocator.

2. Classification of Distribution Costs. Mr. Rimal followed the Electric Utility Cost Allocation Manual published by NARUC to conduct a MSS to calculate the classification factors used to distribute the cost of poles, conductors, and conduits between

customer and demand. He explained that the costs of certain distribution assets are not only related to demand and that AES Indiana has classified these distribution plant accounts between customer and demand in past cases. He stated that the Commission has affirmed the use of MSS to classify certain distribution costs as customer-related.

Mr. Rimal explained that the basic customer approach recommended by CAC witness Barnes is not a recognized classification method by NARUC for embedded COSS. Mr. Rimal explained that the classification of pole and conductor costs between customer and demand is an established practice in Indiana and continues to be based on cost causation. Mr. Rimal believes this classification method should continue to be approved by the Commission.

3. Revenue Distribution and Mitigation. Mr. Rimal disagreed with OUCC witness Deupree's position regarding AES Indiana's proposal to cap the proposed rate increases at 1.3 times the proposed system average coupled with no reduction to any rate class. Mr. Rimal explained that the main goal of this proposal was to reduce the inter-class subsidies and move classes closer to their cost of service, while ensuring that impacts on any one particular class is moderated. He testified the 1.3 times constraint was put in place due to gradualism considerations. Mr. Rimal showed that the cap of 1.15 times the system increase proposed by Mr. Deupree is restrictive and fails to reduce the current subsidy provided by rate classes.

Mr. Rimal disagreed with CAC witness Inskip's proposal that the revenue increase for the residential class should be no greater than the system average increase. Mr. Rimal testified that Mr. Inskip's proposed outcome would be opposite of cost causation. He stated the residential class at current rates are receiving a subsidy of around \$52 million from other classes. Mr. Rimal testified that if the rate increase for the residential class is capped at 1.15 times the system average increase, the subsidy received would increase.

Mr. Rimal testified IG witness York's concerns about subsidy levels have merit; AES Indiana also considered affordability for each class and determined that the revenue increase experienced by certain classes should be mitigated to moderate the impacts on those classes. Mr. Rimal stated the goal is to move all rate classes towards their cost of service.

In response to City of Indianapolis witness Sommer, Mr. Rimal stated his proposal to tie the revenue increase of one rate schedule to another rate schedule is counter to the concept of cost causation. Mr. Rimal testified the revenue allocated to each class should reflect the cost of providing service to that class, subject to other considerations like gradualism.

Mr. Rimal updated his mitigation proposal to reflect the reduction to the total revenue requirement reflected in Petitioner's rebuttal filing.

4. Rate Design.

a. Cost Basis for Customer Charge. Mr. Rimal explained that OUCC witness Deupree's and CAC witness Barnes's calculations did not accurately capture the customer-related costs. Mr. Rimal testified that AES Indiana proposes to recover about 17% of the fixed costs from residential class and about 18% of the fixed costs from the Small Secondary rate

schedule in the proposed customer charge. He added that the proposed customer charge recovers about 59% of the customer costs for the residential class and about 88% of the customer costs for the Small Secondary rate schedule. Mr. Rimal explained that the portion of the costs contained in administrative and general costs, uncollectible costs, supervision and engineering costs, and customer-related costs should be part of any customer charge calculations. Mr. Rimal explained that the recommendations of OUCC witness Deupree and CAC witness Barnes would not result in efficient pricing. Mr. Rimal testified that setting the volumetric rates higher by lumping fixed costs into the variable charge distorts the price signals provided to customers. Mr. Rimal testified that the rate design proposed in this proceeding recovers a portion of the fixed costs in the variable energy charge, thereby overstating the marginal cost of energy. Mr. Rimal stated the declining block rate structure represents a compromise approach, in which successively larger rate blocks move closer to the marginal cost of energy. Mr. Rimal added that the declining block rate design reduces the variability of AES Indiana's earnings associated with year-to-year fluctuations in usage and can provide benefit to weather-sensitive customers who would not see their bills fluctuate as widely in response to weather variations. Mr. Rimal explained that the Commission has previously determined that recovering demand-related costs in a declining block rate is more cost-justified than recovering through a flat volumetric rate.

Mr. Rimal showed that the rate structure proposed by CAC witness Barnes would harm the low-income/high-usage customers, while only providing a smaller benefit to the low-income/low-usage customers. Mr. Rimal added that one could draw the same conclusion regarding the impact on non-low-income/high-usage customers, i.e., disproportionate negative impact on high users while small positive impact on low users. Mr. Rimal stated a distorted rate structure that recovers a significant portion of fixed cost in variable charges will continue or even exacerbate the intra-class subsidy that currently exists. He explained that that even though energy conservation and energy efficiency are a desirable policy objective, distorting price signals to achieve energy efficiency goes counter to achieving economic efficiency.

b. Multi-Family Rate. Mr. Rimal disagreed with CAC witness Barnes that multi-family customers require less distribution infrastructure than non-multi-family customers. Mr. Rimal explained that the primary distribution infrastructure needed will not be different whether you are serving multi-family or non-multi-family customers. He added that it is not clear whether the amount of secondary distribution infrastructure would be significantly different whether a utility is serving multi-family or non-multi-family customers. Mr. Rimal concluded that the cost of serving multi-family customers and non-multi-family customers are not significantly different and a separate multi-family rate is not warranted at this time. Mr. Rimal added that the billing system as currently designed and implemented does not have a flag to indicate the housing type and the count of units and testified that creating such a field would require additional time and resources. Finally, Mr. Rimal testified that reducing the revenues collected from multi-family residential customers would shift the revenue burden to non-multi-family residential customers and will increase their rates.

c. Rate Design for Secondary Service (Large). In response to Kroger witness Bieber, Mr. Rimal testified that his biggest concern with increasing the demand charge further, while reducing the energy charge for Rate SL, is the resulting bill impacts on certain

customers, especially the low load factor customers. Mr. Rimal testified that Mr. Bieber's proposal would have bill impacts that are more dispersed than Mr. Rimal's proposal.

d. Lighting Analysis. Mr. Rimal testified AES Indiana provided a complete analysis as contemplated by the settlement agreement in Cause No. 45911.

J. Other Matters.

1. Executive Compensation. Mr. Dalton testified that IPALCO Form 10-K/A information relied upon by OUCC witness Latham directly contradicts his statements about the AES Indiana's executive compensation. Mr. Dalton also testified that the parent company corporate executive compensation and board member payments referenced by OUCC witness Latham are not included in AES Indiana's proposed revenue requirement. Mr. Dalton testified that for the executives serving in the roles identified by Mr. Latham, Petitioner's proposed revenue requirement reflects approximately \$4.27 million in compensation costs. Mr. Dalton testified that it is appropriate for AES Indiana to pay its executives some amount in order to attract and retain highly qualified individuals, and explained that the amount paid by AES Indiana to executives reasonably aligns with the median of the market, based on benchmarking that is consistent with industry practices.

2. Environmental Issues. Mr. Cuadra disagreed with CAC witness Inskeep's characterization of Petitioner and explained that AES Indiana complies with the regulations related to coal combustion residuals disposal and management which result in asset retirement obligations reflecting the associated cost of compliance.

3. Potential Data Center Load. Ms. Davis-Handy testified that data centers provide a significant economic development opportunity for Indiana, but she also recognized there are concerns about these large-scale developments and the energy they consume. She testified AES Indiana does not currently have any data center customers, and no such load is expected during the 2026 Test Year being used in this rate review proceeding. She stated that should large loads develop in Petitioner's service area, AES Indiana expects to address it at that time, and will seek any necessary approvals from the Commission in a separate cause.

Mr. Rogers testified that he disagreed with CAC witness Inskeep's proposal that AES Indiana's Phase 2 rates be denied based on the potential that new data centers could take service in 2027 and beyond. Mr. Rogers explained that AES Indiana's filing utilizes a forward-looking test period determined on the basis of projected data for the 12 months beginning on January 1, 2026, and ending December 31, 2026, which is allowed by statute. Ind. Code § 8-1-2-42.7(d) and added that the two-step rate increase is a commonly used and well understood mechanism to comply with the used and useful requirement. Mr. Rogers testified that it is premature to assess the cost allocation and customer safeguard concerns raised by Mr. Inskeep because the characteristics of this type of potential new load and the estimated costs to serve it are not yet known. Mr. Rogers stated these matters can be addressed by the Commission in the future.

4. **Rate Implementation.** In response to OUCC witness Eckert and IG witness York, Ms. Aliff clarified that AES Indiana proposes to implement Phase 1 rates for service rendered on and after the date the Commission approves Petitioner's new tariff, assuming that approval comes expeditiously and no more than 20 days after AES Indiana files its compliance tariffs in this proceeding. She testified Petitioner proposes Phase 2 rates will be effective on a service rendered basis on the date that Petitioner's rate base certification is made or January 1, 2027, whichever is later.

5. **Storm Reporting.** Mr. Holtsclaw testified that AES Indiana agrees with OUCC witness Eckert's recommendations regarding storm reporting requirements and added that Petitioner has already been and intends to continue to follow the agreed-upon criteria for storm reporting.

6. **Streetlighting Matters.** Ms. Aliff testified that AES Indiana plans to submit the report from Cause No. 45911 in accordance with the previously established 2026 deadline.

7. **TDSIC Plan.** Mr. Holtsclaw responded to CAC witness Inskeep's statement regarding increased investment due to the TDSIC spending. Mr. Holtsclaw explained that Mr. Inskeep does not identify any TDSIC spending that he considers unjust and unreasonable, nor does he provide any evidence that recovery of this investment is not in the public interest. Mr. Holtsclaw added that AES Indiana's TDSIC investments are made pursuant to the TDSIC plan approved by the Commission in Cause No. 45264 and are subject to review in separate TDSIC proceedings.

14. **Settlement Overview.** The Settlement Agreement resolves all pending issues in this Cause among the Settling Parties, which does not include the OUCC or the CAC. The Settlement Agreement, admitted into the record as Joint Exhibit No. 1, is attached to this Order, and is incorporated by reference. We discuss the terms of the Settlement Agreement and supporting evidence and the opposition evidence below.

A. **Settling Parties' Testimony.** Mr. Rogers testified that AES Indiana's initial case-in-chief supported an incremental revenue deficiency of \$192.9 million, which Petitioner proposed to implement in two steps – 4.5% in Phase 1 (\$85.4 million) and 5.6% in Phase 2 (\$107.5 million). He stated that updates and concessions reflected in AES Indiana's rebuttal reduced the revenue deficiency to \$187.2 million, which reduced the overall rate revenue increase to 9.5%. Mr. Rogers stated that Settling Parties have agreed to a revenue increase of \$90.7 million, which further reduces the overall revenue increase to 4.7%. He stated AES Indiana proposes implementing the settled increase in two steps. The Phase 1 rate increase of approximately 1.9% (\$35.1 million) would be implemented upon issuance of the Commission's Final Order approving the Settlement Agreement and subsequent tariff approval. The Phase 2 increase of approximately 2.8% (\$55.6 million) would be implemented in January 2027 in accordance with the process set forth in Petitioner's Exhibit No. 27.

Mr. Rogers stated that while the agreed increase is less than AES Indiana originally requested, much of that difference reflects the resolution of the issue regarding which depreciation methodology to use, agreement on reduced ROE, and creative problem solving with respect to vegetation management. He testified that the agreed reduction also reflects an update to AES Indiana's cost of debt, use of ratemaking constructs, such as longer amortization periods, to mitigate the rate impact on customers, and Petitioner's effort to be responsive to the overall concerns raised in this proceeding.

Mr. Rogers testified that AES Indiana invited all parties to participate in the settlement negotiations. He stated that the OUCC and CAC declined to participate; all other parties engaged in the process. Mr. Rogers testified that providing a comprehensive settlement package to the Commission reduces controversy and facilitates the efficient processing of this rate review proceeding. He stated the Settling Parties were able to consider and evaluate the issues and positions of all parties, including the OUCC and CAC due to the prefiled testimony. Mr. Rogers stated that the Settling Parties reached a settlement that is comprehensive, balanced and reflects compromise that occurs in the negotiation process.

Mr. Rogers testified 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 the docket. He stated the Settlement Agreement incorporates concessions by AES Indiana, including a reduction to the proposed revenue increase by 53%. Mr. Rogers stated that while all customer classes benefit from the negotiated reduction in the revenue requirement, the residential customer class received the greatest benefit in terms of the monetary reduction to its revenue requirement. In his opinion, the Settlement Agreement is in the public interest and reasonably resolves all issues in this docket.

IG witness Gorman testified that the Settlement Agreement results in a revenue deficiency of approximately \$90.7 million, which is over 50% less than the \$192.9 million revenue deficiency initially sought by AES Indiana in its case-in-chief. He stated the agreed upon revenue requirement reflects total reductions equal to about 75% of the total value of the adjustments proposed by the IG.

Mr. Rogers presented a bill analysis showing that AES Indiana's residential bill will remain comparatively low. Mr. Elliot showed that actual bills for AES Indiana's customers remain in line with median income growth in Marion County, Indiana, and that the proposed Settlement Agreement reduces the share of wallet percentages estimated for the years 2026 and 2027. He testified that the reduction in the revenue requirement and associated rates and charges improves affordability for AES Indiana's customers and added that Petitioner will continue to offer programs and services that are designed to help customers save energy and money.

IG witness Gorman testified that about 59% of AES Indiana's requested revenue increase was tied to the return on and of new rate base which had been pre-approved for recovery. Accordingly, he stated that a portion of AES Indiana's requested increase was not subject to litigation risk. Mr. Gorman stated that as such, the agreed upon reduction in revenue requirement cannot simply be evaluated against the total base revenue increase in Petitioner's case-in-chief, but rather, needs to be viewed against the amount which was truly subject to potential modification by

the Commission through litigation. Mr. Gorman stated that, taking that into consideration, the agreed ROE and the agreement to utilize the ALG method to calculate depreciation expense were important concessions. In his opinion, the total package, including the O&M adjustments, is a reasonable balance between the interests of both AES Indiana and its ratepayers.

IG witness Gorman testified the overall outcome reflects a balance between the interest on the part of the utility for just compensation for its dedication of its prudent investments to the public use and the interests in customers avoiding excessive charges for their use of the system. He stated the Settlement Agreement was the product of arm's length negotiations conducted in good faith by a range of parties with diverse interests represented by competent counsel. Despite differing viewpoints on particular issues, the Settling Parties were able to achieve consensus on the terms of the Settlement Agreement resolving all issues in this case. In his opinion, the Settlement Agreement, taken as a whole, is a reasonable resolution and consistent with sound ratemaking principles.

Walmart witness Lyon agreed that the Settlement Agreement represents significant compromise between the Settling Parties based on the evidence presented on the issues in this Cause. He added that while he understands that not all parties have joined, Walmart does believe that the Settlement Agreement as an overall resolution of this Cause represents a fair and reasonable compromise that attempts to address affordability in the economic interest of AES Indiana's ratepayers.

The Settling Parties further supported the specific Settlement Agreement terms as summarized below and recommend the Commission approve, without modification, the Settlement Agreement as a just and reasonable resolution of the issues in this Cause:

1. Section I.A.2(a) (Cost of Capital). AES Indiana completed a debt issuance at a cost lower than what was reflected in the forecast. This reduced cost was reflected in Petitioner's rebuttal filing and is also reflected in the Settlement Agreement.

2. Section I.A.2(b) (Cost of Capital). The Settling Parties have agreed to an authorized ROE of 9.75%, which is a 15-basis point reduction to the 9.90% ROE that the Commission authorized in AES Indiana's most recent base rate case. Mr. Rogers testified this downward reduction is significant given market evidence showing cost of capital has increased. Mr. Rogers stated that the agreed ROE is 45 basis points below the low end of the range presented by Petitioner's ROE expert.

Mr. Rogers testified that even after giving effect to the increase of equity in AES Indiana's capital structure, AES Indiana would continue to have the lowest authorized equity layer component of its capital structure relative to its in-state peers. He stated the return to shareholder (equity) portion of the return on rate base is lower in comparison to other Indiana utilities and this structure incentivizes Petitioner to continue to manage its business efficiently to support credit metrics while paying debt service and meeting operational needs.

Mr. Rogers explained that, in reaching its decision to agree to this ROE, AES Indiana considered the positions taken regarding the transition of Petitioner's billing system, utility rate increases, and affordability. Mr. Rogers testified that ROE is important to AES Indiana's financial health and added that failure to provide a return consistent with market expectations could eventually increase financing costs, which may be recovered from customers.

IG witness Gorman testified that the 9.75% ROE is within his recommended range and is well below the range recommended by AES Indiana's witness McKenzie. Mr. Gorman added that the agreed upon ROE is also lower than AES Indiana's current authorized ROE of 9.90%. Given the totality of the evidence in this case, Mr. Gorman considered the 9.75% ROE to be reasonable.

Walmart witness Lyon also supported the Settlement Agreement ROE. He explained for the purposes of settlement, Walmart believes that the 9.75% ROE provides AES Indiana the opportunity to earn a fair return while still protecting customers' expectations of safe and reliable service at just and reasonable rates. He added that the agreed-upon ROE of 9.75% constitutes a reduction in AES Indiana's currently authorized ROE, which Walmart believes reflects a meaningful compromise by AES Indiana and responds to the concerns on critical issues of affordability for AES Indiana's ratepayers.

3. Section I.A.2(c) (Cost of Capital). IG witness Gorman and AES Indiana witness Rogers testified that, similar to the settlements reached in Petitioner's last two rate cases, Section I.A.2(c) of the Settlement Agreement reflects a Prepaid Pension Asset of \$100.3 million (reduced from \$133.5 million) to be included in AES Indiana's capital structure. Mr. Rogers stated that this item, together with the foregone equity return on the billing system agreed to in Section I.A.10. of the Settlement Agreement, has the effect of reducing AES Indiana's return on equity to approximately 9.63%.

4. Section I.A.2(d) (Cost of Capital). Mr. Rogers explained that as part of the Settlement Agreement, this section reflects a 7.03% Rate of Return (WACC) on AES Indiana's original cost rate base and results in an authorized NOI of \$390 million as reflected in Section I.A.2(e) of the Settlement Agreement.

5. Section I.A.3. (Fuel Oil Inventory). Mr. Rogers explained that this section accepts OUCC witness Eckert's proposal to adopt a fuel oil inventory level of 800,128 gallons, reducing the revenue requirement by \$37,000.

6. Section I.A.4. (Forecasted Test Year Revenue). Mr. Rogers explained that this section accepts OUCC witness Leader's proposal to increase forecasted Test Year Revenues.

7. Section I.A.5. (Depreciation Rates and Expense). This section sets forth the agreement to utilize the ALG procedure as calculated by Mr. Spanos for depreciation rates and expenses. Mr. Rogers testified that Petitioner had presented ELG and ALG methodologies in this case and proposed using the ELG method based on the recommendation of its depreciation expert. Mr. Rogers stated the OUCC and the IG disagreed with AES Indiana's proposal to use ELG and instead proposed the continued use of ALG. He testified that the Settling

Parties agreed to the use of ALG and further agreed that use of this methodology in this case reasonably considers affordability. He stated the Settlement Agreement preserves AES Indiana's right to propose alternative methodologies to calculate depreciation rates in its next rate case but also obligates AES Indiana to include an update to its depreciation rates using the ALG procedure.

Mr. Rogers testified that Section I.A.5 also sets forth the agreement to adjust the service lives of assets included in FERC accounts 353 and 365 by \$2.2 million, consistent with the recommendation of IG witness Andrews.

Mr. Rogers stated the combination of using the ALG procedure and adjusting the service lives of FERC accounts 353 and 365 reflected in Section I.A.5 reduces the Phase 2 revenue requirement by \$40.0 million.

8. Section I.A.6. (Distribution Vegetation Management). Section I.A.6. reduces distribution vegetation management expense by \$6 million and extends the trim cycle to six years. Mr. Rogers testified that, consequently, \$36.6 million in vegetation management expense on AES Indiana's distribution facilities is embedded in the basic rates revenue requirement. Mr. Rogers stated that the Reserve will continue as established in Cause No. 45029.

9. Section I.A.7 (Amortizations). Mr. Rogers testified that this section sets forth an agreed amortization period for certain regulatory assets of four years instead of three years as initially proposed by AES Indiana. Mr. Rogers stated that this provision reasonably mitigates the rate impact of this cost recovery.

10. Section I.A.8 (Public Utility Fee and Revenue Conversion Factor). Section I.A.8 provides that the Public Utility Fee of 0.1750% will be used to determine the Public Utility Fee and the revenue conversion factor for pro forma present and proposed rates. Mr. Rogers pointed to a recent legislative amendment and stated the Settlement Agreement reasonably reflects the Public Utility Fee at the currently effective statutory rate for the 12-month period ending December 31, 2026.

11. Section I.A.9 (Major Storms). This section sets forth the agreement to amortize the Major Storm Damage and Restoration Reserve deferral over four years instead of three years, which results in a \$1.2 million reduction in the revenue requirement.

12. Section I.A.10 (CIS). This section provides that the equity portion of the "return on" end of Test Year rate base amount of the CIS portion of the ACE Project will be removed from the revenue requirement in this case.

This section of the Settlement Agreement also provides that the approximately \$40 million in incremental uncollectible accounts expense and the approximately \$7 million in forgone late fees related to the CIS billing system shall not be recovered through the revenue requirement established in this case or any future case.

Mr. Rogers testified that while AES Indiana disagreed with the consumer parties regarding various aspects of the CIS issues, Petitioner recognizes that the transition to the new system had unexpected challenges that impacted customers. He stated these issues were considered in negotiating the Settlement Agreement ROE, and Section I.A.10 further addresses these concerns. He added that the Settlement Agreement reasonably resolves concerns regarding AES Indiana transition to the new billing system.

13. Section I.A.11 (Payroll Expense). This section of the Settlement Agreement provides a reduction of \$4.0 million inclusive of adjustment to Payroll Tax Expense. Mr. Rogers testified that this section increases the adjustment presented in AES Indiana's rebuttal testimony in response to the OUCC.

14. Section I.A.12. (Rate Case Expense). This section of the Settlement Agreement reduces rate case expense reflected in Petitioner's case in chief by \$1.5 million and amortizes rate case expense over four years instead of three years.

15. Section I.A.13 (Base Cost of Fuel). This section of the Settlement Agreement provides that AES Indiana's proposed base cost of fuel will be reduced by \$15.1 million, which results in a \$0.04381 per kWh base cost of fuel in this case. Mr. Rogers stated Petitioner also agreed to present an updated natural gas hedging plan in a future fuel cost proceeding following approval of the Settlement Agreement.

16. Section I.A.14 (TDSIC Plan 2.0) and Section I.A.15. (Next AES Indiana Basic Rates Case). AES Indiana's current TDSIC Plan, approved in Cause No. 45264, enters its final year in 2026. As part of this Settlement Agreement, AES Indiana agreed to delay the start of its next proposed TDSIC plan until no sooner than January 1, 2028. Section I.A.14 also reflects Petitioner's agreement that, at least six months before the planned filing date for its next proposed TDSIC Plan, it will initiate a stakeholder process open to all parties in this Cause to discuss the TDSIC plan proposal.

Section I.A.15 reflects AES Indiana's agreement that it will not seek to implement a change in basic rates and charges as a result of its next base rate case prior to January 1, 2030. Mr. Rogers testified that Sections I.A.14 and I.A.15 are reasonably responsive to customer concerns regarding the frequency of base rate cases and rate increases.

17. Section I.A.16 (Public Facing EV Rate). In his direct testimony, Walmart witness Lyon recommended AES Indiana assemble interested parties to develop an EV tariff. Mr. Elliot responded to this recommendation in his rebuttal testimony, explaining that Petitioner is open to convening a meeting with interested stakeholders to consider various DCFC rate designs. The Settlement Agreement reflects AES Indiana's commitment to a stakeholder process to begin within six months of the date of the Final Order in this Cause with the intent of developing a public-facing EV Rate to facilitate charging at customer-owned locations in a filing prior to AES Indiana's next electric base rate case. Mr. Rogers stated this provision reasonably resolves this issue.

18. Section I.A.17(a) (Other). This section of the Settlement Agreement provides that the new base rates approved by the Commission in this Cause will be implemented AES Indiana for service rendered on and after the date the Commission approves Petitioner's new tariff.

19. Section I.A.17(b) (Other). AES Indiana proposed a new property tax rider as part of its case-in-chief, which the OUCC opposed. Mr. Rogers explained that, as part of the Settlement Agreement, Section I.A.17(b) of the Settlement Agreement reasonably responds to the OUCC position by providing that Petitioner will withdraw its request for approval of a new tax rider.

20. Section I.A.17(c)-(h) (Other). Mr. Rogers opined that the remaining provisions of this Section reasonably address customer specific issues. Section I.A.17(c)-(h) reflects agreements between AES Indiana and the City of Indianapolis. Section I.A.17(i) memorializes AES Indiana's commitment to engage in discussions with Rolls-Royce on ways to ameliorate the peaks associated with its engine testing, such as use of battery storage.

21. Section I.B. Section I.B. of the Settlement Agreement sets forth the agreement on revenue requirement allocation and rate design. Mr. Rogers testified that, under the Settlement Agreement, cost increases are fairly distributed across the rate classes while being mindful of the principles of cost causation, gradualism, and subsidy mitigation. AES Indiana's residential customer charge remains unchanged compared to current rates in response to the opposition to Petitioner's proposed increase in this charge.

Mr. Rimal testified that the settlement revenue allocation as well as the settlement rate structure and rates are just, reasonable, and not preferential or discriminatory. He added that the settlement rate structure and rates are expected to provide AES Indiana with a reasonable opportunity to earn the required return on its invested capital and recover its operating expenses.

The testimony in support of the Settlement Agreement explained that numerous principles were considered in reaching agreement on revenue allocation. First, the settlement revenue requirement decrease agreed to in this Settlement Agreement will be allocated so that all major rate classes receive a benefit as a direct result of the negotiated reduction in the proposed revenue increase reflected in AES Indiana's case-in-chief. Second, no class will receive an overall rate decrease from current rates as a result of the rates implemented pursuant to this Settlement Agreement. Additionally, the Settlement Agreement revenue allocation maintains Petitioner's proposal of a 1.3 times system average increase with the added component of a residential subsidy reduction target of 15%.

Mr. Rimal presented an analysis indicating that the revenue allocation approach reflected in the Settlement Agreement balances the need to move classes closer to their cost of service, while ensuring that the impact on any one particular class is moderated. Mr. Rimal testified that each rate code benefits from the reduced settlement revenue requirement regardless of whether the settlement is compared to rebuttal or to AES Indiana's direct case. He also testified that, measured from either starting point, the residential class is receiving the largest benefit in total dollar terms

and one of the largest benefits in terms of percentage reduction. IG witness York added that the residential class is still receiving about \$41.1 million in mitigation efforts.

Mr. Rimal explained that the rate increase caps for individual classes must be determined within the context of the overall system increase. The size of the overall revenue increase informs the reasonableness of a capped increase for a rate class. Additionally, the goals of reducing intra-class subsidies and gradualism are also considered. Mr. Rimal testified that a cap lower than 1.3 times system average, such as 1.15 times system average, would result in the subsidy received by the residential class increasing relative to the current subsidy. Mr. Rimal stated that the Five Pillars directs the state to take affordability into consideration, including ratemaking constructs that result in retail electric utility service that is affordable and competitive across residential, commercial, and industrial classes, and testified that affordability is a concept which must be applied across the system as a whole.

Walmart witness Lyon stated that while the agreed revenue allocation does not adopt his proposal, the revenue allocation set forth in the Settlement Agreement is cost-based and still gradually moves rate classes closer to cost of service and does so in a reasonable and fair manner. He testified Walmart continues to maintain, and intends to advocate in future rate cases, that greater movement to rectify subsidies is necessary. Mr. Lyon stated that Walmart believes the settled revenue allocation carefully and intentionally balances the interests of all of AES Indiana's rate classes by not imposing burdensome subsidy mitigation proposals while also ensuring that this issue is addressed.

Walmart witness Lyon and AES Indiana Rimal testified the Settling Parties agreed that the Rate SL customer charge shall be set at \$128.00 as proposed by AES Indiana in rebuttal, the demand charge be set at \$28.50, and any remaining allocated revenues be recovered through the energy charge. Mr. Lyon stated that by increasing the demand charge more than originally proposed by Petitioner, Rate SL will move further towards charges that align with cost of service principles.

IG witness York stated that the Settling Parties did not agree on a particular cost allocation methodology. She testified the Settlement Agreement uses an agreed revenue allocation which considers the positions presented by the parties in the case to reach a fair and reasonable result, which is consistent with cost-of-service principles.

IG witness York testified that both her own and AES Indiana's COS studies, which are based on the CP methodologies, reveal that several customer classes, particularly the commercial and industrial classes, are contributing revenues above, or just below, their class cost of service. She stated conversely the COS studies reveal that other classes, notably the residential class, were contributing below their cost of service, which indicates the need for an allocated revenue increase to bring the classes closer to their cost of service.

IG witness York testified that the agreed revenue allocation reflects a similar dynamic. She stated it reveals revenue to cost ratios greater than 1.0 for many rate classes, including the commercial and industrial classes; this indicates that those rate classes are contributing revenues to the system, which are greater than the cost to serve them. She stated other classes, including the

residential class, have a revenue to cost ratio less than 1.0; which means these classes contribute less than the costs to serve them, and that they receive subsidies from those customers with a revenue to cost ratio greater than 1.0.

IG witness York testified the agreed revenue allocation is consistent with the results of the COS studies prepared and presented by herself and AES Indiana witness Rimal. She stated the agreed revenue allocation provides for some reduction in interclass subsidies, moving customer classes closer to their cost of service. She testified that mitigation strategies to avoid rate shock were used by the Settling Parties to manage rate impacts. She concluded that overall, these results further the overarching principles of cost-of-service ratemaking, by promoting efficient use of the system, encouraging conservation of resources, providing for stability, and generally reflecting equity. Ms. York added that all customer classes received substantial benefits from the revenue reduction, so that no customer class received disproportionate increases or decreases.

B. OUCC and CAC Opposition Testimony. The OUCC recommended the Commission reject the Settlement Agreement and requested the Commission order a rate decrease in accordance with the OUCC's case-in-chief. The OUCC requested the Commission adopt the 9.00% ROE supported by its case-in-chief and then reduce it by an additional 50 basis points as also supported by its case-in-chief.

The OUCC witnesses argued that the Settlement Agreement did not adequately address the issues raised by each witness. OUCC witness Eckert testified that the positions he took in his direct testimony remain unchanged and added that the Settlement Agreement does not reasonably incentivize AES Indiana to resolve its ongoing customer complaints. OUCC witness Lantrip reiterated his previous recommendations regarding the Major Storm Damage and Restoration Reserve account and the billing system deployment. Mr. Lantrip also testified regarding the test year true-up mechanism, arguing that the true-up mechanism should not be used as a cleanup for expenses that were not included in Petitioner's rate case. OUCC witness Baker continued to recommend that rate case expense be shared equally by ratepayers and shareholders. OUCC witness Sanka also continued to recommend the level of distribution vegetation management expense as proposed in her direct testimony. OUCC witness Kelley also testified that AES Indiana did not adequately support several projects in its capital forecast, and stated the true-up mechanism should not be used to transfer dollars allocated from one project to another.

OUCC witness Garren also continued to recommend the adjustments to the depreciation issues raised in his initial testimony relating to changes to service lives, contingency, escalation of terminal retirement estimates, and the adjustment to net salvage costs that were not addressed in the Settlement Agreement.

OUCC witness Deupree continued to recommend his ACOSS, particularly the classification and allocation of generation resources. Mr. Deupree also discussed his concerns with Petitioner's share of wallet analysis.

CAC witness Inskip recommended the Commission deny the Settlement Agreement and stated that, to the extent the Commission approves the Settlement Agreement, the Commission should make modifications to address and resolve concerns identified in CAC's testimony. Mr.

Inskeep stated the Settlement Agreement targets residential customers with the largest rate increase of any customer class, contrary to the principle of cost causation, the affordability pillar, and the mandate for just and reasonable rates. Mr. Inskeep testified that the Settlement Agreement is an unbalanced arrangement that benefits AES Indiana and the narrow interests of its largest electricity users, which exacerbates the residential affordability crisis. He also testified that elected officials representing Indiana customers oppose the Settlement Agreement. Mr. Inskeep testified that customers have provided evidence regarding unaffordable and inadequate service. He contended that the Settlement Agreement did not adequately address the billing system issues.

Mr. Inskeep testified the residential bill increase raises concerns both about the frequency of recent rate increases and the magnitude of the rate increase. He testified that, if approved, the Settlement Agreement would result in a bill for 1,000 kWh increasing by more than \$23 per month between May 2025 and January 2027, a compound annual growth rate of 8.7%. He demonstrated that AES Indiana's residential bills are climbing at a rate that exceeds inflation. Mr. Inskeep contended that errors in Mr. Elliot's share of wallet analysis resulted in the understatement of the affordability problems. Mr. Inskeep testified that when AES Indiana's share of wallet analysis is corrected to include sales tax and include trackers, it produces a higher share of wallet than Petitioner calculated.

Further, Mr. Inskeep noted that AES Indiana did not provide a share of wallet analysis for households with incomes below the median for Marion County. Mr. Inskeep testified his analysis utilizing alternative household income levels shows that lower-income households will pay a significantly higher share of their income on AES Indiana electric bills than median household income customers. Based on his analysis, he testified the Settlement Agreement could have harmful impacts on the affordability of electric service for lower-income households.

Mr. Inskeep continued to advocate in favor of adoption of his proposed Affordable Power Rider and for the reduction or elimination of security deposits. He stated that AES Indiana witness Elliot's concerns with the Affordable Power Rider are not quantified, and had Mr. Elliot performed such an analysis then he would have been aware that the bill impact would be modest and unlikely to pose a material concern to customer affordability broadly, while providing affordability benefits to the population of AES Indiana customers that Mr. Elliot recognizes is experiencing the greatest affordability challenges. He also responded to Mr. Elliot's concerns about cost causation, stating that there is a strong public policy rationale for funding low-income programs by collecting revenues to fund such a program from all ratepayers that outweighs cost causation in this instance. He further discussed his independent review of CAD complaints included with the OUCC's direct testimony, supported his position with the RCA submitted by Petitioner, and stated that he believes there is a pattern of billing and CIS issues. Mr. Inskeep disagreed that the Settlement Agreement included meaningful concessions related to the billing system issues, and reinforced the necessity for a full and independent investigation into all of the billing issues experienced by AES Indiana customers.

Mr. Inskeep testified that the residential class receive the largest percentage (6.51%) rate increase of any customer class and the largest absolute (\$54.4 million) rate increase. He stated the Settlement Agreement does not provide a reasonable resolution to the contested classification, allocation, and revenue apportionment issues in this case. He testified the Settlement Agreement

produces a worse outcome for the residential class than had only the mitigation steps in AES Indiana's case-in-chief been applied.

Finally, Mr. Inskeep expressed concern about potential unintended consequences of the Settlement Agreement to not seek to implement a change in basic rates and charges as a result of its next base rate case prior to January 1, 2030, due to the potential for new data center load. He testified that the Settlement Agreement would foreclose an AES Indiana-initiated rate case to address the significant impacts that such a large load customer could have on utility costs, revenues, cost allocation, and rates and that he is opposed to a blanket rate case stay out provision.

C. Settlement Rebuttal Testimony. AES Indiana witnesses Rogers, McKenzie, Illyes, Spanos, Holtsclaw, Coklow, Elliot, Flint, Bramley, Dickerson and Rimal presented rebuttal testimony in support of the Settlement Agreement. IG witnesses Gorman and York also presented settlement rebuttal testimony.

Mr. Rogers stated that all parties were invited to join settlement discussions. He testified that the OUCC and CAC declined to do so. He reiterated that settlements advance matters with greater speed and certainty, and less drain on public and private resources than litigation. He stated these factors incent parties to enter into a settlement agreement and explained that if these incentives are eliminated, then the public policy objectives favoring settlement would not be achieved.

IG witness Gorman explained that the OUCC witnesses did not offer any new evidence; rather their opposition to the Settlement Agreement rested on the fact that it does not incorporate positions taken by the OUCC in its case-in-chief. He testified this criticism is unreasonable and suggests the only resolution is the full adoption of the OUCC's positions. He testified that the outcome of each case is a product of many factors.

Mr. Gorman testified the Settlement Agreement should be considered as a whole that results in just and reasonable adjustments to customers' rates. He added that any settlement, the one in this cause included, reflects the give-and-take compromises needed to resolve all the individual contested issues. He testified that the reasonableness of the Settlement Agreement should be viewed in the aggregate to assess if the Settlement Agreement supports just and reasonable adjustments to tariff rates that are in the public interest.

IG witness Gorman and AES Indiana witness Rogers continued to recommend the Commission find the Settlement Agreement is a fair and reasonable compromise and is in the public interest.

15. Commission Discussion and Findings. Indiana law favors settlement as a means of resolving contested proceedings. *Mendenhall v. Skinner & Broadbent*, 728 N.E.2d 140, 145 (Ind. 2000). As the Commission has stated, the policy of supporting settlement recognizes that

“settlements help advance matters with far greater speed and certainty and far less drain on public and private resources than litigation or other adversarial proceedings.”²

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 Coalition of Ind. v. Pub. Serv. Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission’s rules allow for settlement and recognize that settlement may not be agreed to by all the parties. If, on examination, the Commission finds the settlement to be in the public interest, then the settlement should be approved, and its terms form the substance of the Commission’s order. The Commission’s procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Thus, 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.

These standards apply whether the settlement is unanimous, or is contested by one or more parties. In *Nextel West Corp. v. Indiana Utility Regulatory Commission*, 831 N.E. 2d 134 (Ind. Ct. App. 2005) *trans. denied*, 860 N.E.2d 58 (Ind. 2006), the Indiana Court of Appeals affirmed the Commission’s approval of a settlement agreement over objection from opposing parties. *Id.* at 140-58. That decision included affirming the Commission’s authority to do so provided the settlement was supported by sufficient evidence and found to be in the public interest. *Id.* at 156. Other cases, too, have reached the same conclusion. *See, e.g., Citizens Action Coalition v. NIPSCO*, 796 N.E.2d 1264, 1267-72 (Ind. Ct. App. 2003) *trans. denied*, 812 N.E.2d 799 (Ind. 2004).

It cannot be otherwise, because the evaluation of the public interest is broader and more complex than just assessing whether every participant had its own proposal adopted as part of the Settlement Agreement. The evaluation of the Settlement Agreement requires a broader view with consideration of existing and future customers of all kinds, as well as the interest of the utility, and Indiana as a whole. As explained by the Indiana Supreme Court:

² *Ind. Mich. Power Co.*, Cause No. 43774 PJM-7 at 8, 2017 WL 1208967, at *8 (IURC Mar. 29, 2017); see also *Ind. Bell Tel. Co.*, Cause No. 41911 at 2, 2001 WL 1708038, 213 P.U.R.4th 515 (IURC Dec. 4,2001) (citing *Mendenhall*, 728 N.E.2d at 145).

We repeatedly hear the expression that it is the duty of the commission to represent the public alone. If, by this remark, it is meant that the commission is organized but for one purpose, that of antagonistic action toward utilities under any and all circumstances, then one of the great purposes of the law, adequate service by the utility at the least cost to the consumer, might be entirely defeated. The theory of the law creating the commission is that it shall be conscientiously and impartially administered by a body composed of a personnel especially qualified by knowledge, training, and experience pertaining to the subject-matter committed to it for award consonant with reasonable fairness and substantial justice according to legislative mandate, and the circumstances shown relative to its effect in the future on the utility's ability to serve the interest and convenience of the public; the cost and expense to the parties interested being an element for consideration.

In re NW. Ind. Tel. Co., 201 Ind. 667, 674-75, 171 N.E. 65, 68 (1930).

In the current Cause, the Commission has before it substantial evidence from which to judge the reasonableness of the Settlement Agreement and to evaluate whether it is in the public interest. We have summarized the evidence and contested issues raised in this case prior to the filing of the Settlement Agreement. We have also summarized both the evidence supporting the Settlement Agreement, and the evidence opposing it. All parties had an opportunity to participate in settlement negotiations. Because not all the parties entered into the Settlement Agreement, we find it is appropriate to address the outstanding concerns of the non-settling parties. Our review and findings upon the respective issues are set forth below.

A. Depreciation. The Settlement Agreement reasonably adopts the ALG procedure for depreciation. The Settlement Agreement is not unreasonable merely because it did not remove contingencies from depreciation expense, change the contingency percentage in the decommissioning cost estimate, or adopt Mr. Garren's position regarding a lack of evidence to support escalation. The Commission has ruled that decommissioning costs should be escalated to the time at which the facilities will be retired and FERC is also in favor of including escalation. To exclude escalation would not only ignore the reality of inflation, but would result in future generations of customers paying for generating plants serving today's customers. The Commission has also held that the inclusion of contingency is appropriate.³ The 20% contingency factor in the Settlement Agreement is consistent with industry standard and consistent with AES Indiana's two previous rate cases. Further, the mass property service lives and net salvage percentages in the depreciation study in the Settlement Agreement incorporate all the proper factors for determining these estimates. As explained by depreciation authorities, such as NARUC, estimating service lives must necessarily include a subjective component. Service life estimates are a forecast of the future and focusing only on mathematical calculations based on historical data will lead to unreasonable service life estimates. Therefore, the Commission finds the Settlement Agreement depreciation rates are reasonable and represent a fair compromise on all the parties' positions concerning updating AES Indiana's depreciation rates.

³ See *PSI Energy Inc.*, Cause No. 42359 at 70-71 (IURC May 18, 2004).

B. Capital Structure and ROE. The ROE is intended to provide a utility with a reasonable opportunity to attract capital on terms comparable with businesses of similar risk. In setting the rate of return, the Commission's decision must be framed by *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591 (1944); see also *Indianapolis Power & Light Co.*, Cause Nos. 44576/ 44602 at 41, 2016 WL 1118795 at 43 (IURC Mar. 16, 2016).⁴ The general standards these cases established require a ROE set by the Commission to be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns of other businesses of comparable risk.

The Commission is also mindful that "the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment." *Indiana-American Water Co.*, Cause No. 44022 at 35 (IURC June 6, 2012). Due to this lack of precision, the use of multiple methods is desirable, in part, because no one method will produce reasonable results under all conditions and circumstances. The Commission is also mindful of the strengths and weaknesses of the various models typically used to estimate a utility's cost of common equity, and we find that with appropriate and reasonable inputs, models, such as the DCF model and the CAPM can produce reasonable estimates of a utility's cost of common equity and are commonly relied on in regulatory proceedings. Consistent with the standards in *Hope* and *Bluefield*, as well as under Indiana law, AES Indiana's authorized return on equity should be reasonable given the totality of the circumstances.

The parties proposed various returns using the models and other methods as basis for their positions. AES Indiana's analysis produced a range of 10.2% to 11.2%. Petitioner ultimately proposed the Commission adopt a ROE of 10.7%. The OUCC's analysis produced a range of 7.73% to 9.27%, and recommended a ROE of 8.5%. The IG's analysis produced a range of 9.1% to 9.9%, and recommended a ROE of 9.5%. Based on the discussion below and review of the evidence presented by various parties, we find that a range of 9.1% to 9.9% is reasonable. We note that the ROEs granted to Indiana's vertically integrated electric utilities have been trending lower over time. See, e.g. 9.9% in *Indianapolis Power & Light Company d/b/a AES Indiana* Cause No. 45911 (IURC April 17, 2024), 9.85% in *Indiana Michigan Power Company* Cause No. 45933 (May 8, 2024); 9.8% *Southern Indiana Gas and Electric Company* Cause No. 45990 (February 3, 2025); and 9.75% in *Duke Energy Indiana* Cause No. 46038 (January 29, 2025). These recent Commission decisions further support the reasonableness of the range 9.1% to 9.9%. This range will frame establishing an authorized ROE that is commensurate with the returns of other businesses, specifically Indiana IOUs, of comparable risk. While the Settling Parties agreed upon a ROE of 9.75%, which is within our range, the Commission does not find that it balances the interest of the investors, ratepayers, and other stakeholders; therefore, the Commission does not accept the agreed upon ROE.

The Commission's ROE determination needs to consider the mitigation of risk associated with various regulatory mechanisms, including AES Indiana's use of a forecasted test year and the riders and/or trackers approved for AES Indiana. In Cause No. 43526, the Commission noted "[w]e must also consider the effect tracking mechanisms have in reducing risk in order to ensure that

⁴ See also *Re Centerpoint Energy Indiana*, Cause No. 45990 at 54, 2025 WL 461911 at *54 (IURC Feb. 3, 2025); *Re Duke Energy Indiana, LLC*, Cause No. 46038 at 37, 2025 WL 414846 at *34 (IURC Jan. 29, 2025).

these reduced risks are properly reflected in NIPSCO's cost of equity...No witness for NIPSCO addressed the effects of trackers on NIPSCO's cost of capital, which could be considered a fatal failing of its analysis."⁵ Overall, AES Indiana's tracker mechanisms are generally consistent with that of other Indiana IOUs and allow Petitioner to lower its shareholder risk, which also affects its ability to attract capital.

In Cause No. 43526, the Commission noted "a utility's operational and financial performance were appropriate considerations in determining a utility's cost of equity. The Commission has a unique role in regulating its jurisdictional utilities, which at times requires us to send a clear and direct message to utility management concerning the need for improvement in the provision of its utility service. Our determination of the authorized cost of common equity capital can be a very direct means to incent improved service."⁶

Throughout this proceeding AES Indiana ratepayers have voiced their concerns surrounding affordability and quality of service. OUCG witness Bishop testified that prior to September 2, 2025, the OUCG received over 6,800 consumer comments; the OUCG filed an additional 177 consumer comments on December 12, 2025. Ms. Bishop noted that the OUCG received more written comments in this rate case than other Indiana IOU rate cases. Ms. Bishop estimated that about 500 people attended the field hearings; she testified that 89 customers spoke and 53 customers provided written comments. Through both the field hearings and written comments, ratepayers stated that current bills negatively impacted their daily lives, and voiced concerns about the effect of the proposed rate increase. Further, customers discussed numerous issues with the implementation of the CIS billing system and the difficulty they faced in attempting to resolve the issues they experienced. Ratepayers also shared the various issues that occurred with regards to vegetation management. Not only have ratepayers had difficulty receiving a response from AES Indiana, AES Indiana also fails to respond to customer complaints filed with CAD in the allotted time required under 170 IAC 16-1-5(c)(3). The OUCG made a request to review CAD complaints under the Access to Public Records Act ("APRA"). Ms. Bishop stated that the OUCG's APRA request contained 868 CAD complaints, of which 412 had surpassed the 14-day deadline under 170 IAC 16-1-5(c)(3).

In consideration of affordability, the OUCG proposed an adjustment of 30 basis points to the authorized ROE. In consideration of quality of service, the OUCG proposed an additional 20 basis point adjustment to the authorized ROE. The affordability adjustment will be addressed below. The Commission finds that any necessary quality of service adjustment is provided for in the Settlement Agreement and the additional commitments made by AES Indiana. Settlement Term I.A.10(a) removes the equity portion of the return on the CIS billing system and AES Indiana committed to apply a lifetime non-recovery exclusion at the hearing, which ensures that shareholders are not rewarded for the low quality of service during the implementation of the CIS billing system.

⁵ *Northern Indiana Public Service Company*, Cause No. 43526 at 32 (IURC May 18, 2004).

⁶ *Id.*

AES Indiana witness Illyes testified that Petitioner would fail to attract capital for investment if AES Indiana is not awarded a fair ROE. He testified that a downward adjustment to ROE would negatively impact AES Indiana's credit rating. The Commission notes that while the cost of equity is determined primarily by various methodologies, which can be weighed to varying degrees, the mathematical metrics utilized by various credit rating agencies are less subjective. AES Indiana's confidential response to the Commission's docket entry leads to the finding that a moderately lower authorized ROE can support positive credit quality and access to capital needed by AES Indiana. Further, at the hearing, Petitioner acknowledged that additional options, such as dividend payment discipline, could also help support its credit quality. Based on the foregoing, the Commission finds adjusting the authorized ROE downward would not unreasonably jeopardize AES Indiana's access to capital.

The Commission's determination of an authorized ROE is integral in balancing the Five Pillars. In this proceeding, we consider the competing objectives of ensuring the utility has access to the capital required to maintain reliability, while working to provide service to its customers at affordable rates. While acknowledging that AES Indiana is in an elevated capital investment cycle and attraction of capital is critical, we also must consider how to reasonably manage customer affordability. The Commission has previously elected to address the 'return of' effects of the elevated capital cycle the industry is currently in by supporting the alteration of its precedent on depreciation expense methodology. The Settlement Agreement adopts this same methodology, which reduces the revenue requirement by \$37.758 million. We now find it appropriate to address the 'return on' effects. We find this can be addressed by altering the weight applied to the competing objectives: investment support and customer affordability. Accordingly, we find that the evidence of record warrants a modification of the Settlement Agreement ROE of 9.75% to 9.50%.

C. Rate Case Expense. The Commission recently explained the two-tiered test used in Indiana to assess rate case expense.⁷ Given that rate case expense is reasonably necessary in light of the service provided, the rate case expense requested here satisfies this test. As AES Indiana is a regulated utility, Commission approval is required for Petitioner to change its rates and charges. AES Indiana's rate review is part of a structured process necessary to allow rates to continue to reflect the underlying cost of providing service. A utility seeking rate relief under Ind. Code § 8-1-2-42.7 is further required to present a case-in-chief that includes the submission of extensive information and materials. AES Indiana should be able to recover the cost of complying with this regulatory requirement, especially when the evidence shows the expense was necessary to present the case and the rate case expense amount is reasonable and in line with the amount accepted in Petitioner's most recent rate cases, despite the present case being more complex.

This Commission has previously rejected invitations by the OUCC to allocate rate case expense to shareholders.⁸ We find that the record in this current Cause does not provide sufficient evidence to reach a different conclusion.

⁷ *Duke Energy Indiana*, Cause No. 46038 at 73-74, 2025 WL 414846 at*71 (IURC Jan. 29, 2025) (explaining two-tiered test considers whether: (1) the expense is reasonably necessary to the presentation of the case, and (2) the amount is reasonable in light of the service provided).

⁸ *Duke Energy Indiana*, Cause No. 46038 at 74, 2025 WL 414846 at *72 (IURC Jan. 29, 2025); *S. Ind. Gas and Elec. Co.*, Cause No. 45990 at 68, 2025 WL461911 at *68 (IURC Feb. 3, 2025).

The Settlement Agreement reduced rate case expense by \$1.5 million and extended the amortization to four years from three years, resulting in a \$0.8 million reduction in the revenue requirement. The Commission finds the overall result contained in the Settlement Agreement is reasonable.

D. Amortization Expense. In a rate case, the Commission considers test year costs and adjustments but the acceptance of such costs does not freeze that cost. Estimates used by the Commission can only be reasonable approximations. Absent a statutory exception (which does not exist here), rates remain the same notwithstanding changes in expenses. *Indiana Gas Co. v. Office of Util. Cons. Counselor*, 575 N.E.2d 1044, 1052 (Ind. Ct. App. 1991); *Re Ind. Mich. Power Co.*, Cause No. 39314 at 168, 1993 WL 602559 at 100 (IURC Nov. 12, 1993). “No one can know with exactitude what the future holds.” *Evansville v. Southern Ind. Gas & Elec. Co.*, 167 Ind. App. 472, 489, 339 N.E.2d 562, 574 (Ind. Ct. App. 1975) quoting *Boone County Rural Elec. Membership Corp. v. Public Serv. Comm’n*, 239 Ind. 525, 535, 159 N.E.2d 121, 125 (1959).

The record shows the Settling Parties did not ignore this issue. The Settlement Agreement extends the amortization period to four years instead of three years as initially proposed by AES Indiana. Section I.C. of the Settlement Agreement clarifies that any matters not addressed by the Settlement Agreement will be adopted as proposed by AES Indiana in its direct and rebuttal case. The extension of the amortization period reasonably aligns with the rate case period contained in the Settlement Agreement. The Commission finds this to be a reasonable term of the Settlement Agreement.

E. Capital Forecast and True-Up Mechanism. AES Indiana has provided substantial evidence to support its capital expenditure forecast, and demonstrated the capital budget is developed from an analysis of historical experience and an assessment of what is known about upcoming projects during the period covered by the forecast. Petitioner also presented a comparison of the forecasted capital expenditures to recent actual periods, which shows the forecasted level of capital investments is reasonable, as compared to prior years, and considers inflation and certain growth investments.

The OUCC’s criticism of AES Indiana’s capital forecast is based upon the erroneous assumption that the capital budget forecast remains fixed in time and should not evolve to reflect changes in business and market conditions. This ignores evidence explaining that while Petitioner manages operations to the overall forecast, the future will likely unfold in a manner that differs from the details used to build the forecast. We agree with Petitioner that the overall level of forecasted spending is reasonable and necessary to provide reasonable and adequate service.

With respect to the specific projects identified by the OUCC, we note that AES Indiana presented substantial evidence to support its forecasted investment. Moreover, Commission approval of the overall revenue requirement and forecasted rate base does not require preapproval of each and every individual project comprising that forecast.⁹ Rather, our task is to consider whether the overall level of ongoing capital expenditures is projected to be used and useful, and whether the level of expenditures is reasonable. The evidence submitted by Petitioner offers

⁹ *Indiana Michigan Power Co.*, Cause No. 45235 at 15, 2020 WL 1656243 at *14-15 (IURC Mar. 11, 2020) (quoting *American Suburban Utils.*, Cause No. 41254 at 14, 1999 WL 397655 (IURC Apr. 15, 1999)).

sufficient information to allow the Commission to review the reasonableness of the utility's projections, and of AES Indiana's business judgment that the projected investment is necessary. Given the evidence presented, the Commission finds Petitioner has sufficiently demonstrated the reasonableness of its capital forecast.

Finally, we note AES Indiana's proposed rate base true-up mechanism reasonably resolves the OUCC's concerns regarding specific capital projects. To the extent such projects are not certified as used and useful as of the Test Year rate base cut off, they will not be reflected in rates. Accordingly, we find Petitioner's capital forecast is reasonable, supported by substantial evidence, and is approved.

With respect to the true-up mechanism, the record shows Petitioner proposes to implement new base rates in two phases to reasonably reflect rate base and revenue requirement updates at the time rates are placed into effect. Specifically, Petitioner proposes to implement the PRA Phase 1 credit as part of the compliance filing following issuance of the Commission's order in this Cause. PRA Phase 2 will be implemented effective January 1, 2027.

Per the Settlement Agreement, Petitioner intends to implement new rates on a service-rendered basis. Further, while we agree with Ms. Aliff that a 30-day review period for Petitioner's Phase 2 compliance filing is appropriate, we disagree that a review period is not necessary for the Phase 1 compliance filing. Ultimately, we find that Petitioner's implementation of Phase 1 shall include a 30-day review period, and Phase 2 rates shall be implemented as set forth in Ms. Aliff's direct testimony, which includes a 30-day review period.

Per the Settlement Agreement, Petitioner intends to implement new rates on a service-rendered basis, and no party objected to this approach. Prior to Phase I rates becoming effective, AES Indiana shall file its new schedule of rates and charges and full tariff, revised to comply with the findings of this Order, and revenue proof for all customer classes for approval by the Commission's Energy Division. This filing shall apply and be consistent with the text of this Order, notwithstanding whether it is determined any numbers need revision; provided, the propriety of any such revisions shall be explained in the filing. Any party contesting the derivation of rates and charges shall file a notice within ten business days of AES Indiana's filing of the new rate schedules and proof of revenues.

Accordingly, we further find that AES Indiana shall certify to this Commission its rate base at December 31, 2026, and thereafter calculate the resulting Phase 2 rates consistent with the Settlement Agreement. For purposes of the Phase 2 certification, AES Indiana shall use the forecasted test year end rate base shown on AES Indiana Attachment CAR1-S, Schedule RB1-S, line 9, included with Petitioner's Exhibit No. 4. The Phase 2 rates shall go into effect on the date that AES Indiana certifies its test year end rate base, or January 1, 2027, whichever is later. The rate base for Phase 2 rates shall not exceed the lesser of: (a) AES Indiana's forecasted test year end rate base as modified by the Settlement Agreement or (b) AES Indiana's certified test year end rate base. AES Indiana shall serve all parties with its certification. The OUCC and intervenors shall have 30 days from the date of certification to state objections to Petitioner's certified test year end rate base. If there are objections, AES Indiana will be afforded an opportunity to respond. Once

the Commission decides the matter, the Phase 2 rates will be trued-up (with carrying charges) retroactive to January 1, 2027, notwithstanding when Phase 2 rates go into effect.

F. Vegetation Management. The Settlement Agreement reduces Petitioner's initial proposed vegetation management expense from \$42.6 million to \$36.6 million and Settling Parties agreed to a six-year cycle. Both AES Indiana's initial proposal and the Settlement Agreement include an expense level that represents a material increase in this expense. AES Indiana witness Flint noted that Petitioner's initial proposal offered a mitigated expense by extending the trim cycle from four to five years, with a resulting annual expense of \$42.6 million. Settling Parties agreed to a more mitigated expense by further extending the trim cycle to six years, resulting in an annual vegetation management expense of \$36.6 million.

While the Commission appreciates the efforts of Settling Parties, we find that further mitigation is appropriate. We acknowledge that the proposed expense is based primarily on competitively bid and negotiated contract costs and acknowledge the OUCC's concerns that AES Indiana's proposal shifts more costs onto customers without the commensurate assurance of benefits. Accepting the OUCC's proposal to maintain the level of distribution vegetation management expenses authorized in Cause No. 45911, or \$25.247 million, effectively extends the trim cycle to approximately eight years. A vegetation management trim cycle represents an ongoing commitment to reliability and extending the trim cycle, which effectively reduces the annual miles trimmed, offers an appropriate balance between those reliability efforts and customer affordability. The continued application of the trimming methodology AES Indiana has initiated also presents an opportunity to reasonably expect that extending the trim cycle will offer a lower risk to reliability than under the prior methodology. Accordingly, we find that the extension of the trim cycle will serve as a meaningful step toward the Commission's rebalancing of the Five Pillars with an enhance weighting of affordability and thus we modify the Settlement Agreement to reflect the OUCC's recommended vegetation management expense.

G. Major Storm Damage Restoration Reserve. Section I.A.9 of the Settlement Agreement sets forth the Settling Parties' agreement to amortize the Major Storm Damage Restoration Reserve regulatory asset balance of \$14.1 million over four years instead of three years, resulting in a \$1.2 million reduction in the revenue requirement. The Settlement Agreement accepted AES Indiana's proposed amount of \$7.3 million for ongoing major storm expense (excluding base labor) to be included in the revenue requirement. The actual major storms from 2025 support the prudence of embedding \$5.0 million in the revenue requirement as reflected in the Settlement Agreement. Accordingly, the Commission accepts this portion of the Settlement Agreement.

H. Base Cost of Fuel. In the Settlement Agreement, AES Indiana agreed to reduce its proposed base cost of fuel by \$15.1 million, resulting in a base cost of fuel of \$0.04381 per kWh. Additionally, as part of the Settlement Agreement, Petitioner committed to representing an updated natural gas hedging plan to the Commission for review in a future fuel cost proceeding. The Commission finds this portion of the Settlement Agreement to be reasonable and is also supportive of the continued agreement between Petitioner and the OUCC and other intervenors to file testimony in FAC cases 35 days after AES Indiana files its case-in-chief.

I. Public Utility Fee. The Public Utility fee accepted in the Settlement Agreement is consistent with current Indiana law.

J. Uncollectible Accounts Expense. The calculation for uncollectible accounts expense reflected in the Settlement Agreement is consistent with Commission precedent, and substantial evidence supports the view that it is reflective of utility operations going forward. The Commission accepts this portion of the Settlement Agreement.

K. COSS/Rate Design. As recently stated, “We [the Commission] have never found that fixed production costs should be allocated on any basis other than demand.”¹⁰ The production plant costs are fixed in nature and do not vary with the amount of energy generated. The demand classification method reflected in AES Indiana’s study recognizes that the utility may call on any of those resources during peak periods. We again find that the allocation methods proposed by the non-settling parties would result in higher load factor customers being negatively impacted and would discourage efficient use of the system, which benefits all customers. We remain hesitant to change cost-allocation methodologies in ways that produce large shifts in class cost responsibility absent clear evidence of a material change in system operating characteristics; doing so without substantial evidence would be contrary to the public interest. Accordingly, the Commission finds that no portion of fixed production costs should be allocated exclusively on the basis of energy and accepts this portion of the Settlement Agreement.

The Commission also accepts the Settlement Agreement’s adoption of the 12CP method used for production costs. Use of the CP methodology has been regularly approved by the Commission, including in settlements.¹¹ The 12CP method was used based on the FERC tests and consistency with AES Indiana’s recent rate cases. AES Indiana also chose to use 12CP because it schedules its maintenance during the off-peak and shoulder months. This scheduled maintenance can result in an elevated loss of load probability as the capacity reserve is reduced during these periods. The system capacity reserve often is not much different in the off-peak and shoulder months than it is in the peak months. In Cause Nos. 44576 and 44602, while discussing the allocation of production plant, the Commission stated, “[it] has historically supported using the 12CP methodology if the FERC diversity tests are satisfied.”¹² The Commission further explained:

The Commission’s preference is to “utilize the previously approved allocation methodology, given sufficient evidence, unless system operating characteristics are demonstrated to have changed since the last approved cost of service study allocation methodology.” [citation omitted] Further, we are also cautious to adopt a new allocation methodology without seeing the potential bill impacts on customer classes. Accordingly, we find that the 12CP methodology represents a reasonable means of allocating production cost in this case.¹³

¹⁰ *Duke Energy Indiana, LLC*, Cause No. 46038 at 93 (IURC Jan. 29, 2025).

¹¹ See *Duke Energy Indiana, LLC*, Cause No. 46038 at 94 (IURC 1/29/2025).

¹² *Indianapolis Power and Light Co.*, Cause Nos. 44576/44602 at 66, (IURC Mar. 16 2016).

¹³ *Id.*

Adoption of the 12CP approach for purposes of guiding the Settlement Agreement revenue allocation rather than the 4CP approach resulted in a movement of costs away from residential customers towards commercial and industrial customers. In other words, the settled result is a reasonable compromise that favors residential customer affordability. The Commission finds the evidence in this proceeding shows the use of the 12CP methodology reflected in the Settlement Agreement is reasonable.

The Commission has previously held that the use of a MSS is appropriate to allocate distribution costs.¹⁴ The Commission agrees that the MSS, which follows guidance from the NARUC Manual, provides a sound basis for determining the customer-related component of these costs. The Commission also agrees that allocating these costs between customer and demand using the MSS methodology is appropriate and aligns with industry practice and prior Commission decisions. Therefore, the Commission accepts the use of the MSS in the Settlement Agreement.

In reaching the revenue allocation in the Settlement Agreement, the Settling Parties assessed the percentage of retail subsidy/excess reduction to yield a fair increase across all retail classes and considered gradualism. One of the principles considered in reaching the Settlement Agreement was that no customer class should receive an increase that is more than 1.3 times the overall system increase, subject to the residential subsidy reduction target of 15%. This balancing between the cost-based ratemaking and gradualism provides an appropriate application of the affordability prong of the Five Pillars. Ind. Code § 8-1-2-0.6 directs that affordability includes ratemaking constructs that result in retail electric utility service that is affordable “and competitive across residential, commercial, and industrial customer classes.” The Commission accepts this portion of the Settlement Agreement.

Finally, the declining block rates reflected in the Settlement Agreement are consistent with Commission precedent. The Commission has affirmed that declining block rates are cost-justified compared to flat rates for recovering demand-related costs when the variable energy rates recover a significant portion of these costs. Declining block rates better reflect the cost of service than a flat volumetric rate. Furthermore, AES Indiana’s analysis shows that designing rates that favor low usage low-income customers negatively impacts high usage low-income customers. Accordingly, the Commission accepts this portion of the Settlement Agreement.

L. Other Matters.

1. Next Basic Rate Case. The Settlement Agreement provides that AES Indiana will not seek implementation of new base rates and charges as a result of its next base rate case prior to January 1, 2030. This benefits customers by providing clarity as to the timing of future rate and charge changes. Under HEA 1002 (2026), AES Indiana will be required to file a multi-year rate plan in January 2029. While AES Indiana will be filing its rate case prior to January 1, 2030, it is expected that AES Indiana will not implement rates from that case until January 1, 2030.

¹⁴ *Duke Energy Indiana, LLC*, Cause No 46038 at 97 (IURC Jan 29, 2025).

2. Multi-Family Study. In accordance with the settlement agreement approved in Cause No. 45911, AES Indiana conducted a cost allocation study and designed illustrative rates to evaluate the difference in serving residential multi-family and residential non-multi-family customers. The results of this analysis and a summary of the results of the cost allocation study and the illustrative rate design were filed as AES Indiana Attachment BR-10 in Petitioner's Exhibit No. 6. The multi-family analysis conducted by Petitioner identified the population of potential multi-family customers based on how multi-family customers are defined in its DSM programs. The results of the multi-family analysis indicated that the cost of serving a multi-family customer is similar to the cost of serving a non-multi-family customer. Based on this analysis, AES Indiana concluded that a distinct and separate multi-family rate is not necessary at this time. Based on the record of evidence, we find that AES Indiana has complied with the Settlement Agreement in Cause No. 45911. The Commission accepts this portion of the Settlement Agreement.

3. CAC's Proposed Affordability Rider. CAC witness Inskeep proposed the Commission approve an Affordable Power Rider with the goal of providing financial support for low-income residential AES Indiana customers. The Rider would be a new rider for AES Indiana customers that provides a tiered discount to LIHEAP-qualified residential customers, mirroring the current USF Rider discount percentages used by Southern Indiana Gas and Electric d/b/a CEI South, with costs recovered through a per-kWh charge assessed identically on all retail sales. Mr. Inskeep testified that the primary purpose of the proposed Affordable Power Rider is to make electric service meaningfully more affordable to low-income residential customers using an administratively efficient process and mechanism that is consistent with the Commission's authority under Indiana statute.

While acknowledging affordability is important, AES Indiana witness Elliot testified that a non-cost-reflective discount for a subset of customers would result in unintended consequences, including that other customers would be subsidizing this Rider, which would decrease affordability for customers not participating in this Rider. Mr. Elliot also testified that providing a non-cost-reflective discount on electricity service and the associated energy consumption misaligns the price signal a customer receives to manage their energy usage through behavioral conservation and/or participation in AES Indiana's DSM programs. He concluded by noting that managing energy usage is one of the most powerful tools to realize cost savings and make monthly bills affordable. AES Indiana witness Elliot also testified that, rather than addressing a low-income discount proposal on a stand-alone basis, such a public policy decision should be established legislatively, similar to how energy efficiency programs, payment installment plans, the provision of LIHEAP grants, and many other affordability interventions have been borne out of public policy debate.

While we appreciate CAC's desire for AES Indiana to provide more assistance to low-income customers, the Commission declines to amend the Settlement Agreement to adopt CAC's Affordability Rider. We note that under HEA 1002 (Public Law 36-2026), utilities are directed to offer low-income customer assistance programs, as well as provide notices and post information on their websites no later than July 1, 2026. In developing and implementing these programs, the Commission encourages Petitioner to work the OUCC and other interested parties via a stakeholder process to explore options for affordability programs in a future rate case.

M. Five Pillars. 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.

As such, the Five Pillars have served as the lens through which the Commission has viewed all parties’ requested relief in this Cause and constitute the framework for the findings set forth in this Order. Per the Legislature’s directive, we have considered and evaluated each of the Five Pillars in making our determinations in this case, and our considerations are discussed throughout the findings set forth in the above sections.

OUC witness Latham challenged the consideration of the affordability pillar but testified that AES Indiana’s case-in-chief adequately addresses four of the Five Pillars: resiliency, reliability, stability, and environmental sustainability. Affordability is an important policy consideration, and Indiana statute recognizes this. Cost-of-service ratemaking remains the foundation for allocating class revenue responsibilities. The affordability pillar specifically is framed in terms of class impacts for all customer classes, including the residential, commercial, and industrial classes. The negotiated revenue concessions operate to benefit all rate classes, with the residential class receiving significant benefit. As we have previously explained, “our role in addressing [the affordability concern] is not to reach a conclusion as to whether the rates approved herein are ‘affordable’ for each and every customer, particularly given the difficulty in defining affordability in general and for the many diverse customers and communities [a Utility] serves.” *Indiana American Water Co.*, Cause No. 45870 at 105, 2024 WL 755397 at *9 (IURC Feb. 2, 2024); *Duke Energy Indiana LLC*, Cause No. 46038 at 11, 2025 WL 414846 at *7 (IURC Jan. 29, 2025); *Centerpoint Energy Indiana*, Cause No. 45990 at 121, 2025 WL 461911 at *124 (IURC Feb. 3, 2025).

The Settlement Agreement reduces the overall revenue requirement, which supports affordability while allowing AES Indiana to maintain system reliability, resiliency, and stability. Also, the Commission has already authorized rate increases to reflect AES Indiana’s investments previously approved by the Commission such as the TDSIC projects and investments in clean energy projects, which also contribute to reliability, resiliency, stability, and environmental sustainability.

The Settlement Agreement reasonably addresses affordability by, among other things, reducing the proposed revenue increase by \$111.3 million relative to Petitioner’s case-in-chief and providing revenue mitigation to the residential class. Additionally, by agreeing to not implement new base rates before 2030, the Settlement Agreement adheres to the principles of gradualism and will result in base rate stability for customers. We also considered AES Indiana’s proposed process to phase-in its rates.

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 the Settlement Agreement as modified above is consistent with legislative directives.

16. Conclusion. With the modifications to the ROE and vegetation management, the Commission finds the Settlement Agreement as modified is reasonable. The Settlement Agreement as modified reflects a significant reduction to AES Indiana’s request. The modifications of the ROE and vegetation management are within the established range of reasonableness and reasonably considers AES Indiana’s managerial and operational issues, customer affordability, reliability, and the balancing of interests between investors and ratepayers.

Overall, although not every position by every party is specifically reflected in the Settlement Agreement as modified, its terms do reflect consideration of the testimony presented by all parties. It further reflects the evidence as a whole and is consistent with reasonably expected outcomes based on prior Commission decisions. The settled revenue requirement as further modified by the Commission is supported by the record as a whole and represents a fair compromise on the revenue disputes raised in the litigation phase of this proceeding. Moreover, as shown by AES Indiana witness Rimal and IG witness York, the cost of service and rate design terms of the Settlement Agreement as modified operate in conjunction with the revenue terms to produce rates that are just and reasonable to all classes and which remain consistent with well-accepted cost-of-service principles.

Based on our review of the record, the Commission finds the Settlement Agreement as modified is within the range of potential outcomes and represents a fair, just, and reasonable resolution of the issues presented within the guardrails of the Five Pillars statutory construct. The Commission further finds and concludes the Settlement Agreement as modified is supported by substantial evidence and is in the public interest. Accordingly, the Settlement Agreement as modified is approved.

17. Overall Authorized Increase. Having found, based on the evidence of record, that the Settlement Agreement should be approved, we further approve the revenue increase agreed to in the Settlement Agreement. The proposed revenue increase is based upon a projected test year ending net original cost rate base of \$5,547,426,000 as shown on AES Indiana Attachment CAR-1S, Schedule RB-1S to Petitioner’s Exhibit No. 4 as follows:

Rate Base as of December 31, 2026 (in thousands)		
1	Plant in Service	\$ 7,879,245
2	Accumulated Depreciation and Amortization	\$ (3,592,451)
3	Materials and Supplies Inventory	\$ 118,315
4	Fuel Stock Inventory	\$ 1,704
5	Regulatory Assets	\$ 1,140,614
6	Total Original Cost Rate Base	\$ 5,547,426

We find this original cost is the fair value under Indiana Code § 8-1-2-6 for purposes of this Cause. We further find that a fair return should be authorized based upon this net original cost rate base and a projected WACC of 6.92%, as follows:

Weighted Average Cost of Capital as of December 31, 2026					
	Component of Capitalization	Amount (\$000)	Percent of Total	Return Rate	Weighted Return Rate
1	Long-term Debt	\$ 3,061,302	47.17 %	5.34 %	2.52 %
2	Preferred Stock	0	0.00 %	---	0.00 %
3	Common Equity	\$ 2,996,633	46.17 %	9.5 %	4.39 %
4	Customer Deposits	\$ 11,892	0.18 %	6.00 %	0.01 %
5	Prepaid Pension Asset (net of OPEB liability)	\$ (100,314)	(1.55) %	---	0.00 %
6	Deferred Income Taxes	\$ 520,540	8.02 %	---	0.00 %
7	Post 1970 ITC	\$ 308	0.00 %	0.08 %	0.00 %
8	Totals	\$ 6,490,361	100.00 %		6.92 %

We therefore find that AES Indiana should be authorized to increase its base rates and charges in two steps, calculated to produce additional annual operating revenue of \$71,059,000, total operating revenue of \$1,979,693,000, and total net operating income of \$383,882,000, as follows¹⁵:

Allowable Electric Operating Income Requirement as of December 31, 2026 (in thousands)		
1	Original Cost Rate Base	\$ 5,547,426
2	Weighted Average Cost of Capital	6.92 %
3	Allowable Operating Income	\$ 383,882
4	Less: Adjusted test year operating income at present rates	\$ 330,803
5	Deficiency in operating income	\$ 53,079
6	Revenue Conversion Factor	0.746974
7	Deficiency in operating revenue	\$ 71,059

The rate increase authorized herein should be implemented in two phases as reflected in the Settlement Agreement and approved herein.

¹⁵ This table is intended to reflect the specific changes directed in this order and is subject to refinement pending the energy division reviewed and approved order directed compliance filing. The changes include the application of the directed cost of equity and vegetation management adjustment, as well as the related tax impacts.

18. Effect of Settlement Agreement. The Settlement Agreement is not to 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 respect to future citation of the Settlement Agreement or of this order, we find our approval herein should be treated in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at 7-8 (IURC Mar. 19, 1997).

19. Confidential Information. On June 3, 2025, September 19, 2025, and January 21, 2026, motions seeking a determination that designated confidential information involved in this proceeding be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3 were filed by AES Indiana and the IG. The requests were supported by affidavits showing the designated documents offered into evidence at the evidentiary hearing were trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and Ind. Code § 24-2-3-2. On June 26, 2025, September 29, 2025, and January 22, 2026, the Presiding Officers issued docket entries finding such information confidential on a preliminary basis. The parties subsequently submitted designated confidential information in accordance with this finding.

On January 27, 2026, the OUCC filed its Objection to AES Indiana's Third Motion for Confidential Information, to which Petitioner filed its Verified Reply on January 28, 2026. At the hearing, AES Indiana's Third Motion was granted over the OUCC's objection. After reviewing the designated confidential information, the Commission finds all such information qualifies as confidential trade secret information pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. AES Indiana and the IG take reasonable steps to maintain the secrecy of the information and disclosure of such information would cause harm to AES Indiana and/or the IG. Therefore, we affirm the preliminary rulings and find this information should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29, and held confidential and protected from public disclosure by this 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 as modified.
2. AES Indiana is authorized to adjust and increase its rates and charges for retail electric utility service in accordance with the Settlement Agreement to produce an increase in total annual operating revenues of approximately \$71,059,000, which rates and charges shall be designed to produce total annual operating revenues of \$1,979,693,000, which are expected to produce an annual net operating income of \$383,882,000.
3. The revenue increase shall be implemented in two phases in accordance with the Settlement Agreement as modified.
4. AES Indiana shall file new schedules of rates and charges, along with its revised tariff under this Cause, consistent with the Settlement Agreement as modified and the rates and

charges authorized herein. AES Indiana’s new schedules of rates and charges shall be effective upon approval with the Energy Division of this Commission in accordance with the Settlement Agreement as modified. Phase 1 rates will be implemented on a services-rendered basis as soon as possible following the issuance of this Order and approval of the new AES Indiana tariff. AES Indiana shall verify the calculations of operating income and revenue, as well as its allowable electric operating income requirement as of December 31, 2026. This filing shall include workpapers and revenue proof in the compliance filing under this Cause. Phase 2 rates shall be implemented on a services-rendered basis and subject to true-up as provided in the Settlement Agreement as modified.

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

6. AES Indiana is granted accounting authority for the implementation of the Settlement Agreement as modified.

7. AES Indiana is authorized to file and implement updated factors for its rate adjustment mechanisms in accordance with the Settlement Agreement as modified, and such changes shall be effective simultaneous with approval of AES Indiana’s new basic rates.

8. AES Indiana is authorized to utilize a base cost of fuel of 43.81 mills per kWh and a net operating income of \$383,882,000 in its FAC proceedings. For purposes of computing the authorized net operating income for Ind. Code § 8-1-2-42(d)(3), the increased return shall be phased-in over the appropriate period of time that Petitioner’s net operating income is affected by the earnings modification as a result of the Commission’s approval of this Order. The OUCC will continue to receive a 35-day period to review Petitioner’s FAC applications and to file the OUCC’s testimony in such proceedings.

9. The information submitted under seal in this Cause pursuant to Petitioner’s and the IG’s requests 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.

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

ZAY, VELETA, AND ZIEGNER CONCUR; DEIG DISSENTS; SWINGER NOT PARTICIPATING:

APPROVED: JUN 17 2026

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

_____ on behalf of
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)
THROUGH A PHASE-IN RATE ADJUSTMENT; AND)
FOR APPROVAL OF RELATED RELIEF, INCLUDING)
(1) REVISED DEPRECIATION RATES, INCLUDING) **CAUSE NO. 46258**
COST OF REMOVAL LESS SALVAGE AND)
UPDATED DEPRECIATION EXPENSE; (2))
ACCOUNTING RELIEF, INCLUDING DEFERRALS)
AND AMORTIZATIONS, (3) INCLUSION OF)
CAPITAL INVESTMENT, (4) RATE ADJUSTMENT)
MECHANISM PROPOSALS, INCLUDING A NEW)
PROPERTY TAX RIDER, AND (5) NEW SCHEDULES)
OF RATES, RULES AND REGULATIONS FOR)
SERVICE.)**

STIPULATION AND SETTLEMENT AGREEMENT

Indianapolis Power & Light Company d/b/a AES Indiana (“AES Indiana” or “Company”), AES Indiana Industrial Group (Allison Transmission, Inc., Eli Lilly and Company, Indiana University, Ingredion, Inc., Marathon Petroleum Company LP, and Messer LLC) (“Industrial Group”), 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”) without modification or further condition that may be unacceptable to any Settling Party.

I. TERMS AND CONDITIONS.

A. REVENUE REQUIREMENT. The Settling Parties agree that AES Indiana's proposed revenue requirement (step 2) should be decreased from \$2,110.6 million to \$1,999.3 million, a decrease of \$111.3 million as stated below and reflected in the attached Settlement Agreement Attachment A, which the Settling Parties agree is a summary of revenue requirement impact of the following settlement terms:

1. AES Indiana-OPER Schedule REV 5 Correction: AES Indiana has corrected a sign on REV5-WP5 which lowers the initial increase amount in the Company's case-in-chief by \$5.7 million. This change was necessary to correct the calculation of Net Capacity Rider revenues by netting expenses from the capacity revenues. The effect of this correction is an increase Revenue Requirement at Present Rates and a decrease to the Revenue Requirement Deficiency.

2. Cost of Capital.

(a) Forecasted Debt Issuance. The Company's forecasted debt issuance, 2025 series, has been updated to reflect actual amount of \$350 million and a decrease in interest rate to 5.23049%. This results in a reduction to the revenue requirement of \$1.3 million.

(b) Return on Equity ("ROE"). The agreed authorized return on equity shall be an ROE of 9.75%, which results in a reduction to the revenue requirement of \$32.7 million using the agreed upon Capital Structure and Rate Base.

(c) Prepaid Pension Asset. A Prepaid Pension Asset of \$100.3 million (reduced by \$33.180 million from \$133.5 million) will be included in the Capital Structure, which reduces the revenue requirement by \$2.0 million.

(d) Weighted Average Cost of Capital ("WACC"). After incorporating Sections 2.1 through 2.3 above, the agreed WACC to be applied to AES Indiana's original cost Rate Base is 7.03%.

(e) Net Operating Income ("NOI"). AES Indiana's authorized NOI will be \$390.0 million.

3. Fuel Oil Inventory. The Company agrees to reduce Rate Base by \$1.1 million for Fuel Oil Inventory, consistent with the recommendation of OUCC witness Eckert, which reduces the revenue requirement by \$37,000.

4. Forecasted Test Year Revenue. The Company agrees to increase forecasted Test Year Revenues by \$0.2 million to accept OUCC witness Leader's position.

5. Depreciation Rates and Expense. Solely for purposes of compromise in this proceeding, the depreciation rates and expense will be based on the depreciation rates as calculated by Company witness Spanos using the ALG procedure, which results in a revenue requirement decrease of approximately \$37.8 million. The Settling Parties acknowledge that the ALG procedure shall be applied on a going forward basis to the Company's Test Year end electric plant in service which amount was calculated by the Company using ELG. The Settling Parties agree

that use of this methodology reasonably considers Affordability as that term is used in Ind. Code §§ 8-1-2-0.5 and 8-1-2-0.6. 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. The Settling Parties also agree to adjust the service lives of assets included in FERC accounts 353 and 365 by \$2.2 million, consistent with the recommendation of IG witness Andrews. The combination of these two items is a revenue requirement reduction of \$40.0 million.

6. Distribution Vegetation Management. Distribution Vegetation Management expense will be reduced by \$6.0 million and the trim cycle extended to six years.

7. Amortizations. The amortization period for all regulatory items using three years on AES Indiana Schedule RB8 will be four years instead of three years as proposed by AES Indiana. This reduces the revenue requirement by \$6.3 million.

8. Public Utility Fee and Revenue Conversion Factor. The public utility fee of 0.1750% will be used to determine the Public Utility Fee and the revenue conversion factor for pro forma present and proposed rates as proposed by the Company.

9. Major Storms. The Major Storm Damage and Restoration Reserve deferral will be amortized over four years instead of three years, which decreases the revenue requirement by \$1.2 million.

10. CIS (billing system).

(a) The equity portion of the “return on” the December 31, 2026, end of test year Rate Base amount of the CIS (billing system) portion of the ACE project will be removed from the revenue requirement in this case. This will be implemented through a \$1.9 million expense reduction on AES Indiana Schedule OM19. This expense reduction reflects the equity return, using the Capital Structure agreed to above, on the \$40.7 million December 31, 2026, end of test year Rate Base for the CIS billing system. This agreed reduction applies to this case only; but nothing in this Agreement shall be construed as a limitation on the rights of litigants or the Commission in future proceedings.

(b) The approximately \$40 million in incremental uncollectible accounts expense and the \$7 million in forgone late fees related to the CIS billing system issues discussed in the rebuttal testimony of Company witness Rogers shall not be recovered through the revenue requirement established in this case or any future case.

11. Payroll Expense. AES Indiana Schedule OM19 will be lowered by \$4.0 million inclusive of adjustment to Payroll Tax Expense (total amount reflected on OM19).

12. Rate Case Expense. Rate case expense reflected in the Company’s case-in-chief will be reduced by \$1.5 million and amortized over four years instead of three years, which results in an \$0.8 million reduction in annual revenue requirement.

13. Base Cost of Fuel. As a compromise, the Company’s base cost of fuel will be reduced by \$15 million which results in a \$0.04381 per kWh base cost of fuel in this case. This

results in a \$15.1 million reduction to revenue requirement. Additionally, AES Indiana agrees to present an updated natural gas hedging plan that reflects the Company's test year end portfolio resources to the Commission for review in a future fuel cost proceeding following approval of this Settlement Agreement.

14. TDSIC Plan 2.0. The Company's current TDSIC Plan approved in Cause No. 45264 enters its final year in 2026. As part of this Settlement Agreement package, AES Indiana agrees to delay the start of its next proposed TDSIC Plan until no sooner than January 1, 2028. The Company agrees that, at least six months before the planned filing date for its next proposed TDSIC Plan, it will initiate a stakeholder process open to all parties to this Cause to discuss the anticipated TDSIC investment and projects that the Company intends to include within the TDSIC Plan.

15. Next AES Indiana Basic Rates Case. AES Indiana agrees that the Company will not seek to implement a change in basic rates and charges as a result of its next basic rates case prior to January 1, 2030.

16. Public-Facing Electric Vehicle ("EV") Rate. AES Indiana commits to a stakeholder process to begin within six months of the date of the Final Order in this Cause with the intent of developing a public-facing EV Rate to facilitate charging at customer-owned locations in a filing prior to AES Indiana's next electric base rate case.

17. Other.

(a) The Settling Parties agree that the new basic rates approved by the Commission in this Cause will be applicable only for service rendered by the Company on or after the date the Commission's Energy Division approves the Company's new tariff. More specifically, Step 1 rates will be implemented on a services-rendered basis as soon as possible following the issuance of an Order in this Cause and approval of AES Indiana new tariff. Step 2 rates will be implemented on a services-rendered basis and subject to true-up as proposed by AES Indiana.

(b) The Company will withdraw its request for approval of a tax rider.

(c) AES Indiana shall complete the report contemplated by Paragraph 10.2 from the Cause No. 45911 settlement on or before April 30, 2026. Upon presentation of this Settlement Agreement to the Commission, irrespective of the timing of a Final Order in this docket, the Company shall commence efforts to complete the required report, including establishing meetings with City personnel to obtain input as well as other information. The initial meeting with the City regarding this report shall be scheduled to occur no later than 30 days following the submission of this Settlement Agreement to the Commission.

(d) AES Indiana and the City agree that when relocating streetlights for a capital improvement project, as contemplated by Paragraph 10.4 of the Cause No. 45911 Settlement, "relocation" means up to, and including, 12 feet from the existing site of the streetlight as provided in the restated and revised provision set forth below:

Streetlight relocations for capital projects. AES Indiana agrees that “relocation” as used in this provision means up to, and including, 12 feet from the existing site of the streetlight. 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”. This Section does not address the obligation to pay for the relocation of the facilities. Except for the definition of relocation set forth above, nothing in this Paragraph shall be interpreted to conflict with AES Indiana’s MU-1 tariff, the City Revised Code Sections 645-701 through 645-706, or as amended, or 170 Ind. Adm in. Code §4-1-28.

(e) AES Indiana and the City agree to continue the quarterly meetings with appropriate decision makers from both AES Indiana and the City present agreed to in Paragraph 10.5 of the Cause No. 45911 Settlement. These quarterly meetings will continue irrespective of the timing of AES Indiana’s next base rate case and/or any TDSIC filing. As part of these meetings, AES Indiana and the City agree to engage in discussions regarding new utility poles and ways to facilitate transfers of collocated facilities from the utility pole no longer used by AES Indiana for electric service to the new utility pole to avoid duplication of poles in the City’s rights of way.

(f) Upon presentation of this Settlement Agreement to the Commission, irrespective of the timing of a Final Order in this docket, AES Indiana and the City agree that they will meet within 60 days to discuss a plan and timeline for the conversion to LED of the remaining legacy lighting fixtures used to provide streetlighting to the City. Unless otherwise agreed to by the City and AES Indiana, these meetings will be separate and distinct from the required study under Paragraph 10.2 in the Cause No. 45911 Settlement or the regular quarterly meetings also agreed to in the IURC Cause No. 45911 proceeding. These meetings shall not preclude AES Indiana from considering the conversion of LED lighting as part of its next TDSIC plan submitted to the Commission but any such consideration shall be discussed as part of the stakeholder process agreed to in Paragraph I.A.14 above.

(g) AES Indiana agrees that any new, replaced or relocated Company-owned municipal streetlighting installations shall be in compliance with the Americans with Disability Act (ADA). Any deviations from ADA compliance shall require prior consultation with authorized DPW personnel.

(h) AES Indiana shall analyze and develop a written report regarding vegetation management around Company owned street lighting infrastructure in the City’s rights of way. The Company will solicit input from the City on this analysis. The Company will provide its report to the City (subject to the protection of confidential information) within one year after issuance of a Commission Final Order approving this Settlement Agreement.

(i) AES Indiana agrees to engage in discussions with Rolls-Royce following the rate case on ways to ameliorate the peaks associated with Rolls-Royce’s engine testing, such as use of battery storage.

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

1. Revenue Allocation.

(a) 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 B 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 C.

(b) The Settling Parties agree that Settlement Agreement Attachment D presents the “customer class revenue allocation factor[s] based on firm load,” as that phrase is used in Ind. Code § 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 D have had interruptible load removed. The Settling Parties also agree that Settlement Agreement Attachment D reflects the percentage of distribution and transmission costs allocable to each individual Rate Code. The Settling Parties further agree that the factors will be adjusted to reflect the addition of any large load customers, as that term is defined in Ind. Code § 8-1-7.9-10(a), in each TDSIC 2.0 plan update proceeding under Ind. Code § 8-1-39-9(b).

(c) In reaching the agreement set forth in this paragraph B and associated attachments, the Settling Parties considered the following principles:

(1) The settlement revenue requirement decrease agreed to in this Settlement Agreement will be allocated so that all major rate classes receive a benefit as a direct result of the negotiation reduction in the proposed revenue increase reflected in the Company’s case-in-chief.

(2) No class will receive an overall rate decrease from current rates as a result of the rates implemented pursuant to this Settlement Agreement.

(3) Subject to Item (4), no customer class will receive an increase that is more than 1.3 times the overall system.

(4) The total current rates subsidy received by the residential class shown in AES Indiana witness Rimal’s revenue allocation analysis shall be mitigated by 15%.

2. Residential Customer Charges. The Settling Parties agree that the AES Indiana residential fixed, monthly customer charges shall remain at the current Commission-approved level as set forth below:

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

3. **Secondary Service (Large) Rate Class.** The Settling Parties agree that the Secondary Service (Large) Rate Class customer charge shall be set at \$128.00 as proposed by the Company, the demand charge be set at \$28.50, and any remaining allocated revenues be recovered through the energy charge.

4. **Rates.** The provisions of this Section B will be implemented in the cost of service study and rates included with AES Indiana's testimony supporting this Settlement Agreement.

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 with minimal delay to the April 1, 2026 target order date.

B. The Settling Parties will file testimony specifically supporting the Settlement Agreement, including testimony from AES Indiana, Industrial Group and Walmart. 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 by the Settling Parties in this Cause, will be offered into evidence without objection. The Settling Parties waive cross-examination of each other's witnesses but reserve the right to ask questions of any witness who may be cross-examined by a non-settling party.

C. The concurrence of the Settling Parties with the terms of this Settlement Agreement is expressly predicated upon the Commission's approval of the Settlement Agreement in its entirety without modification of a material condition deemed unacceptable to any Settling Party. If the Commission fails to approve this Settlement Agreement in its entirety, the Settlement Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications. If the Settlement Agreement is withdrawn, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. In the event the Settlement Agreement is withdrawn, the Settling Parties will request an Attorneys' Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

D. 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 15th day of October 2025.

AES INDIANA



Chad Rogers
Director, Regulatory Affairs
AES Indiana
One Monument Circle
Indianapolis, Indiana 46204

AES INDIANA INDUSTRIAL GROUP



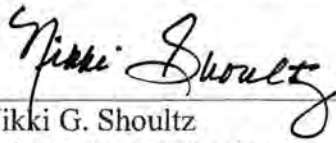
Joseph P. Rompala
Aaron A. Schmoll
Emily R. Vlasak
LEWIS & KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282

WALMART, INC



Barry A. Naum
Steven W. Lee
SPILMAN THOMAS & BATTLE, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050

ROLLS-ROYCE CORPORATION



Nikki G. Shoultz
Kristina Kern Wheeler
Gregory Loyd
Bose McKinney & Evans LLP
111 Monument Circle, Suite 2700
Indianapolis, Indiana 46204

CITY OF INDIANAPOLIS



Anne E. Becker
LEWIS & KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282

Revenue Requirement Impact

Cause No. 46258 (in \$000s)	Financial Schedule	AES Indiana Settlement RR (Proposed) Impact	Rev Req - Present Rates	Rev Req - Proposed Rates	Rev Req Deficiency	Overall Inc
Adjusted Test Year Revenues at Present Rates - Direct Testimony			\$ 1,917,683		\$ 192,931	10.1%
Correct Sign on REV5 WP5 Cell C7	REV5-WP5		\$ 1,923,412		\$ (5,729)	
Starting Point - Revised Ask at Proposed Rates	OPINC		\$ 1,923,412	\$ 2,110,614	\$ 187,202	9.7%
ROE 10.7% to 9.75%	CC2	\$ (32,679)	\$ 1,923,412	\$ 2,077,935	\$ 154,523	8.0%
LT Debt 2025 Issuance	CC1-WP1	\$ (1,301)	\$ 1,923,412	\$ 2,076,634	\$ 153,222	8.0%
Depreciation Expense ALG	DEPR	\$ (37,750)	\$ 1,923,412	\$ 2,038,884	\$ 115,472	6.0%
Depreciation Adjust FERC 353 & 365 ASL	DEPR	\$ (2,214)	\$ 1,923,412	\$ 2,036,670	\$ 113,258	5.9%
Reduce Vegetation Management Expense by \$6M	OM12	\$ (6,051)	\$ 1,923,412	\$ 2,030,619	\$ 107,207	5.6%
Amort 3 yrs to 4 yrs - Reg Assets	RB8-WP1	\$ (6,265)	\$ 1,923,412	\$ 2,024,354	\$ 100,942	5.2%
Amort 3 yrs to 4 yrs - Storm Exp	OM11	\$ (1,180)	\$ 1,923,412	\$ 2,023,174	\$ 99,762	5.2%
Amort 3 yrs to 4 yrs - RC Exp	OM21	\$ (409)	\$ 1,923,412	\$ 2,022,765	\$ 99,353	5.2%
Reduce Rate Case Expense by \$1.5M	OM21	\$ (376)	\$ 1,923,412	\$ 2,022,389	\$ 98,977	5.1%
No Equity "Return on" ACE CIS Component	OM19	\$ (1,912)	\$ 1,923,412	\$ 2,020,477	\$ 97,065	5.0%
Labor Cost Decrease - \$4 million	OM19	\$ (4,023)	\$ 1,923,412	\$ 2,016,454	\$ 93,042	4.8%
Reduce RB Fuel Oil	RB7-WP2	\$ (37)	\$ 1,923,412	\$ 2,016,417	\$ 93,005	4.8%
Increase Test Year Forecasted Revenues	REV4-WP3	\$ 1	\$ 1,923,642	\$ 2,016,418	\$ 92,776	4.8%
Reduce Base Cost of Fuel	OM2	\$ (15,086)	\$ 1,908,632	\$ 2,001,332	\$ 92,700	4.9%
Cause 45911 Prepaid Pension Asset Adjustment (\$33.180 million)	CC2	\$ (2,043)	\$ 1,908,632	\$ 1,999,289	\$ 90,657	4.7%
Rev Req Impact		\$ (111,325)				
Revenue Deficiency Impact				\$ (111,325)	\$ (102,274)	-53.0%

Settlement Agreement Revenue Allocation

6.35%	1.3 times System Increase	First Iteration, Targets 1.3x
-------	---------------------------	-------------------------------

A	B	M	N	O	P	Q	R
		Max if Increase capped at 1.3x System Increase	Classes Over Cap	Classes Under Cap	Additional Mitigation	Interim Revised Deficiency	Classes Under Cap
System Total							
Residential	RS	\$ 53,066,256	\$ (18,273,987)	\$ -	\$ 18,273,987	\$ (53,066,256)	\$ -
Secondary Small [1]	SS	\$ 13,773,825	\$ -	\$ 15,801,037	\$ (7,478,742)	\$ (5,408,729)	\$ 8,322,295
Space Conditioning	SH	\$ 4,836,083	\$ -	\$ 2,054,419	\$ (972,371)	\$ (3,754,035)	\$ 1,082,048
Space Conditioning - Schools	SE	\$ 132,481	\$ -	\$ 257,551	\$ (121,901)	\$ 3,169	\$ 135,650
Water Heating - Controlled	CB	\$ 4,048	\$ (9,997)	\$ -	\$ 9,997	\$ (4,048)	\$ -
Water Heating - Uncontrolled	UW	\$ 10,525	\$ (605)	\$ -	\$ 605	\$ (10,525)	\$ -
Secondary Large	SL	\$ 25,698,870	\$ -	\$ 16,098,311	\$ (7,619,443)	\$ (17,220,003)	\$ 8,478,867
Primary Large	PL-HL	\$ 18,891,970	\$ -	\$ 17,066,456	\$ (8,077,673)	\$ (9,903,187)	\$ 8,988,783
Process Heating	PH	\$ 182,682	\$ -	\$ 222,563	\$ (105,341)	\$ (65,460)	\$ 117,222
Automatic Protective Lighting	APL	\$ 587,864	\$ (1,664,036)	\$ -	\$ 1,664,036	\$ (587,864)	\$ -
Municipal Lighting	MUI	\$ 643,758	\$ (4,426,845)	\$ -	\$ 4,426,845	\$ (643,758)	\$ 0
		\$ (4,564)	\$ (24,375,470)	\$ 51,500,336	\$ -	\$ (90,660,696)	\$ 27,124,866
					Change in Other Revenue	\$ -	
					Total Revenue Deficiency	\$ (90,656,132)	

Notes:
[1] Includes new rate code MD (Small Metered Device)
50% Subsidy Reduction
Increase Capped at 1.3 times System Increase
MD limited to cost to revenue ratio of 1.25
RS Subsidy Reduction Target of 15%

	0	Max if Increase capped at 1.3x System Increase	Classes Over Cap	Classes Under Cap	Additional Mitigation	Interim Revised Deficiency	Classes Under Cap
System Total							
Residential		\$ 53,066,256	\$ (18,273,987)	\$ -	\$ 18,273,987	\$ (53,066,256)	\$ -
Small C&I		\$ 18,756,962	\$ (10,602)	\$ 18,113,006	\$ (8,562,411)	\$ (9,174,168)	\$ 9,539,993
Large C&I		\$ 44,773,522	\$ -	\$ 33,387,330	\$ (15,802,457)	\$ (27,188,650)	\$ 17,584,872
Lighting		\$ 1,231,622	\$ (6,090,881)	\$ -	\$ 6,090,881	\$ (1,231,622)	\$ 0
			\$ (24,375,470)	\$ 51,500,336	\$ -	\$ (90,660,696)	\$ 27,124,866

Notes:
50% Subsidy Reduction
Increase Capped at 1.3 times System Increase
MD limited to cost to revenue ratio of 1.25
RS Subsidy Reduction Target of 15%

Settlement Agreement Revenue Allocation

Second Iteration: Targets MD (within SS) Revenue to Cost Ratio 1.25								
A	B	S	T	U	V	W	X	Y
		Additional Mitigation	Pre-Final Revised Deficiency	Pre-Final Rate Incr.	Pre-Final Revenue Requirement	Mitigation	Current Subsidy Eliminated (%)	Revenue to Cost Ratio
System Total								
Residential	RS	\$ -	\$ (53,066,256)	6.35%	\$ 888,765,895	\$ (42,464,384)	12.23%	0.95
Secondary Small [1]	SS	\$ (1,400)	\$ (5,407,328)	2.49%	\$ 222,708,250	\$ 19,209,329	18.10%	1.09
Space Conditioning	SH	\$ (182)	\$ (3,753,853)	4.93%	\$ 79,913,601	\$ 1,999,148	2.67%	1.03
Space Conditioning - Schools	SE	\$ (23)	\$ 23	0.00%	\$ 2,086,317	\$ 327,543	19.12%	1.19
Water Heating - Controlled	CB	\$ -	\$ (4,048)	6.35%	\$ 67,794	\$ (19,348)	-3.46%	0.78
Water Heating - Uncontrolled	UW	\$ -	\$ (10,525)	6.35%	\$ 176,282	\$ (3,160)	38.17%	0.98
Secondary Large	SL	\$ (1,427)	\$ (17,218,576)	4.25%	\$ 421,930,310	\$ 15,371,514	0.87%	1.04
Primary Large	PL-HL	\$ (1,512)	\$ (9,898,506)	3.33%	\$ 307,413,606	\$ 17,292,774	6.22%	1.06
Process Heating	PH	\$ (20)	\$ (65,440)	2.27%	\$ 2,942,365	\$ 257,289	15.35%	1.10
Automatic Protective Lighting	APL	\$ -	\$ (587,864)	6.35%	\$ 9,845,688	\$ (3,572,697)	6.41%	0.73
Municipal Lighting	MUI	\$ (0)	\$ (643,758)	6.35%	\$ 10,781,808	\$ (8,398,010)	-5.74%	0.56
		\$ (4,564)	\$ (90,656,132)	4.88%	\$ 1,946,631,916	\$ 0		1.00

Notes:

- [1] Includes new rate code MD (Small Metered Device)
- 50% Subsidy Reduction
- Increase Capped at 1.3 times System Increase
- MD limited to cost to revenue ratio of 1.25
- RS Subsidy Reduction Target of 15%

		Additional Mitigation	Pre-Final Revised Deficiency	Pre-Final Rate Incr.	Pre-Final Revenue Requirement	Mitigation	Current Subsidy Eliminated (%)	Revenue to Cost Ratio
System Total								
Residential		\$ -	\$ (53,066,256)	6.35%	\$ 888,765,895	\$ (42,464,384)	12.23%	0.95
Small C&I		\$ (1,605)	\$ (9,175,732)	3.10%	\$ 304,952,245	\$ 21,513,513	16.90%	1.08
Large C&I		\$ (2,959)	\$ (27,182,522)	3.86%	\$ 732,286,281	\$ 32,921,577	3.88%	1.05
Lighting		\$ (0)	\$ (1,231,622)	6.35%	\$ 20,627,495	\$ (11,970,706)	-1.79%	0.63
		\$ (4,564)	\$ (90,656,132)	4.88%	\$ 1,946,631,916	\$ 0		1.00

Notes:

- 50% Subsidy Reduction
- Increase Capped at 1.3 times System Increase
- MD limited to cost to revenue ratio of 1.25
- RS Subsidy Reduction Target of 15%

Final Iteration: Targets 15% Residential Reduction							
Z	AA	AB	AC	AD	AE	AF	
Additional Mitigation	Final Revised Deficiency	Final Rate Incr.	Final Revenue Requirement	Total Mitigation	Current Subsidy Eliminated (%)	Revenue to Cost Ratio	
\$ (1,340,717)	\$ (54,406,972)	6.51%	\$ 890,106,611	\$ (41,123,667)	15.00%	0.96	
\$ 288,517	\$ (5,118,811)	2.36%	\$ 222,419,733	\$ 18,920,812	19.33%	1.09	
\$ 103,528	\$ (3,650,325)	4.79%	\$ 79,810,073	\$ 1,895,621	7.71%	1.02	
\$ -	\$ 23	0.00%	\$ 2,086,317	\$ 327,543	19.12%	1.19	
\$ -	\$ (4,048)	6.35%	\$ 67,794	\$ (19,348)	-3.46%	0.78	
\$ -	\$ (10,525)	6.35%	\$ 176,282	\$ (3,160)	38.17%	0.98	
\$ 546,608	\$ (16,671,968)	4.12%	\$ 421,383,702	\$ 14,824,906	4.40%	1.04	
\$ 398,252	\$ (9,500,253)	3.19%	\$ 307,015,354	\$ 16,894,521	8.38%	1.06	
\$ 3,812	\$ (61,629)	2.14%	\$ 2,938,554	\$ 253,478	16.60%	1.09	
\$ -	\$ (587,864)	6.35%	\$ 9,845,688	\$ (3,572,697)	6.41%	0.73	
\$ -	\$ (643,758)	6.35%	\$ 10,781,808	\$ (8,398,010)	-5.74%	0.56	
\$ (0)	\$ (90,656,132)	4.88%	\$ 1,946,631,916	\$ -		1.00	

\$ 1,340,717 << Additional Mitigation Needed to meet RS Subsidy Reduction Target of 15%

Additional Mitigation	Final Revised Deficiency	Final Rate Incr.	Final Revenue Requirement	Total Mitigation	Current Subsidy Eliminated (%)	Revenue to Cost Ratio
\$ (1,340,717)	\$ (54,406,972)	6.51%	\$ 890,106,611	\$ (41,123,667)	15.00%	0.96
\$ 392,045	\$ (8,783,687)	2.97%	\$ 304,560,200	\$ 21,121,468	18.42%	1.07
\$ 948,672	\$ (26,233,850)	3.72%	\$ 731,337,609	\$ 31,972,905	6.65%	1.05
\$ -	\$ (1,231,622)	6.35%	\$ 20,627,495	\$ (11,970,706)	-1.79%	0.63
\$ (0)	\$ (90,656,132)	4.88%	\$ 1,946,631,916	\$ (0)		1.00

AES Indiana

Demand Factors Used in Rate Adjustment Mechanisms

AES Indiana Confidential Workpaper BR-1.0C-R

ECR		
Current	Proposed	Change

Demand Allocation Factors based on 12 CP Generation in COSS

Residential	44.0%	45.53%	1.52%
Small C&I	14.39%	15.08%	0.69%
Large C&I - PL			
Large C&I - HL			
Large C&I - Primary	17.31%	15.98%	-1.33%
Large C&I - SL & PH			
Large C&I - Secondary	24.06%	23.18%	-0.88%
Large C&I - Total	41.37%	39.17%	-2.21%
Lighting	0.24%	0.23%	-0.01%
Total	100.00%	100.00%	0.00%

OSS, CAP, RTO		
Current	Proposed	Change

Demand Allocation Factors based on 12 CP Generation in COSS

Residential	44.0%	45.53%	1.52%
Small C&I	14.39%	15.08%	0.69%
Large C&I - PL			
Large C&I - HL			
Large C&I - Primary	17.31%	15.98%	-1.33%
Large C&I - SL & PH			
Large C&I - Secondary	24.06%	23.18%	-0.88%
Large C&I - Total	41.37%	39.17%	-2.21%
Lighting	0.24%	0.23%	-0.01%
Total	100.00%	100.00%	0.00%

AES Indiana
Revenue Percentages
Test Year Ended December 31, 2026

TDSIC Allocation Factors

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Rate Class	Rate Code(s)	Total Revenue Requirement	Percent	Class Revenue Allocation - Transmission	Percent	Class Revenue Allocation - Distribution	Percent
Residential	RS, RC, RH	\$ 890,106,611	45.73%	\$ 46,595,338	41.78%	\$ 221,680,708	58.77%
Small C&I	SS, SH, SE, CB, UW	304,560,200	15.65%	18,354,391	16.46%	59,886,172	15.88%
Large C&I - Secondary	SL, PH	424,322,255	21.80%	27,012,119	24.22%	61,389,673	16.28%
Large C&I - Primary	PL, HL	307,015,354	15.77%	19,398,697	17.39%	33,021,117	8.75%
Lighting	APL, MU1	\$ 20,627,495	1.06%	\$ 160,850	0.14%	\$ 1,200,725	0.32%
TOTAL SYSTEM		\$ 1,946,631,916	100.00%	\$ 111,521,395	100.00%	\$ 377,178,395	100.00%

Rate Code Allocations

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Rate Class	Rate Code	Total Revenue Requirement	Percent	Class Revenue Allocation - Transmission	Percent	Class Revenue Allocation - Distribution	Percent
Residential Service (Rate RS) - Codes RS, RC, RH	RS	\$ 890,106,611	45.73%	\$ 46,595,338	41.78%	\$ 221,680,708	58.77%
Secondary Service (Small) (Rate SS)	SS	222,075,425	11.41%	12,879,476	11.55%	44,410,996	11.77%
Municipal Device (Rate MD)	MD	344,308	0.02%	7,061	0.01%	184,591	0.05%
Electric Space Conditioning-Secondary Service (Rate SH)	SH	79,810,073	4.10%	5,315,145	4.77%	14,873,754	3.94%
Electric Space Conditioning-Schools (Rate SE)	SE	2,086,317	0.11%	143,187	0.13%	355,346	0.09%
Water Heating-Controlled Service (Rate CB/CW)	CB	67,794	0.00%	2,004	0.00%	18,378	0.00%
Water Heating-Uncontrolled Service (Rate UW)	UW	176,282	0.01%	7,519	0.01%	43,107	0.01%
Secondary Service (Large) - (Rate SL)	SL	421,383,702	21.65%	26,840,860	24.07%	60,859,959	16.14%
Primary Service (Large) - (Rate PL)	PL	124,707,553	6.41%	8,282,338	7.43%	16,590,305	4.40%
Process Heating (Rate PH)	PH	2,938,554	0.15%	171,259	0.15%	529,714	0.14%
High Load Factor (Rate HL-1) (Primary Distribution)	HL1	142,038,626	7.30%	8,202,715	7.36%	16,430,812	4.36%
High Load Factor (Rate HL-2) (Sub transmission)	HL2	18,873,896	0.97%	1,554,999	1.39%	-	0.00%
High Load Factor (Rate HL-3) (Transmission)	HL3	21,395,279	1.10%	1,358,645	1.22%	-	0.00%
Automatic Protective Lighting - APL	APL	9,845,688	0.51%	102,962	0.09%	626,769	0.17%
Municipal Lighting MU-1	MU1	\$ 10,781,808	0.55%	\$ 57,888	0.05%	\$ 573,956	0.15%
TOTAL SYSTEM		\$ 1,946,631,916	100.00%	\$ 111,521,395	100.00%	\$ 377,178,395	100.00%