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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A MULTI-STEP RATE IMPLEMENTATION OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE, AND APPROVAL OF REGULATORY ASSET TREATMENT UPON RETIREMENT OF THE COMPANY'S LAST COAL-FIRED STEAM GENERATION PLANT; (4) APPROVAL OF AN ADJUSTMENT TO THE COMPANY'S FAC RIDER TO TRACK COAL INVENTORY BALANCES; AND (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO: (A) DEFER TO A REGULATORY ASSET EXPENSES ASSOCIATED WITH THE EDWARDSPORT CARBON CAPTURE AND SEQUESTRATION STUDY, (B) DEFER TO A REGULATORY ASSET COSTS INCURRED TO ACHIEVE ORGANIZATIONAL SAVINGS, AND (C) DEFER TO A REGULATORY ASSET OR LIABILITY, AS APPLICABLE, ALL CALCULATED INCOME TAX DIFFERENCES RESULTING FROM FUTURE CHANGES IN INCOME TAX RATES	)	**CAUSE NO. 46038** **APPROVED: JAN 29 2025**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Commissioner
Greg S. Loyd, Administrative Law Judge

TABLE OF CONTENTS

On April 4, 2024, Duke Energy Indiana, LLC ("Duke," "Petitioner," or "Company") filed its Petition for General Rates and Charges Increase and Associated Relief under Ind. Code § 8-1-2-42.7 and Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements ("Petition") with the Indiana Utility Regulatory Commission ("Commission"). Through this filing, Duke requested authority to increase its retail rates and charges for electric service rendered by Duke in the State of Indiana through a multi-step rate implementation using a forecasted test period; and for approval of related relief including: approval of revised depreciation rates and Duke's proposal for regulatory asset treatment upon retirement of the Company's last coal-fired steam generation plant; an adjustment to Duke's fuel adjustment clause ("FAC") rider to track coal inventory balances in the Company's quarterly FAC filings; approval of necessary and appropriate accounting relief, including authority to: (1) defer to a regulatory asset expenses associated with an upcoming carbon capture and sequestration ("CCS") study to be conducted for the Edwardsport Generating Station ("Edwardsport"); (2) defer to a regulatory asset costs incurred by the Company to achieve organizational savings; and (3) defer to a regulatory asset or liability, as applicable, all calculated income tax differences resulting from future changes in income tax rates; and approval of new schedules of rates, charges, rules, and regulations. Duke contemporaneously filed testimony and exhibits from the following witnesses:[1]

- Stan C. Pinegar, President of Duke
- Joel T. Rutledge, Director of Jurisdictional Planning, Duke Energy Business Services LLC
- Christa L. Graft, Manager, Rates and Regulatory Planning, Duke
- Suzanne E. Sieferman, Director, Rates and Regulatory Planning, Duke
- Kathryn C. Lilly, Manager, Rates and Regulatory Planning, Duke
- Maria T. Diaz, Director, Rates and Regulatory Planning, Duke
- Roger A. Flick, Director of Jurisdictional Rate Administration, Duke Energy Business Services LLC
- Bickey Rimal, Assistant Vice President, Concentric Energy Advisors, Inc.
- Christopher R. Bauer, Director, Corporate Finance and Assistant Treasurer, Duke Energy Business Services LLC
- Adrien M. McKenzie, President of Financial Concepts and Applications, Inc.
- Jeffrey T. Kopp, Senior Managing Director of the Energy & Utilities Consulting Department, 1898 & Co.
- John J. Spanos, President of Gannet Fleming Valuation and Rate Consultants, LLC
- Sean P. Riley, Partner, PricewaterhouseCoopers LLP
- Rebekah E. Buck, Director of Allocations and Reporting, Duke Energy Business Services LLC
- John R. Panizza, Director, Tax Operations, Duke Energy Business Services LLC
- Shannon A. Caldwell, Director, Compensation, Duke Energy Business Services LLC
- William C. Luke, Vice President of Midwest Generation, Duke Energy Business Services LLC
- Peter Hoeflich, Principal Engineer, Generation and Transition Strategy Organization, Duke Energy Carolinas, LLC

1 On June 14, 2024, Duke prefiled corrections to witnesses Pinegar, Spanos, Riley, and Hill testimony. On August 23, 2024, Duke prefiled its second submission of corrections to witnesses Graft, Lilly, Diaz, and Caldwell testimony.

- Timothy S. Hill, Vice President of Coal Combustion Products Projects and Operations, Duke Energy Business Services LLC
- John D. Swez, Managing Director, Trading and Dispatch, Duke Energy Carolinas, LLC
- John A. Verderame, Vice President of Fuels and Systems Optimization, Duke Energy Progress, LLC
- Timothy A. Abbott, General Manager of System Operations, Duke Energy Business Services LLC
- Brian T. Liggett, Vice President of Zone Operations, Duke[2]
- Jacob S. Colley, Director of Customer Services Strategy, Duke Energy Carolinas, LLC

Duke also prefiled its revenue requirement model in PDF (Pet. Ex. 25) and Excel (Pet. Ex. 26) formats on April 4, 2024.

The Indiana Office of Utility Consumer Counselor ("OUCC") participated throughout this proceeding. Additionally, Petitions to Intervene were filed on April 9, 2024, by Wabash Valley Power Association, Inc. ("Wabash Valley"), Nucor Steel ("Nucor"), and the Citizens Action Coalition of Indiana, Inc. ("CAC"); on April 12, 2024, by the Duke Industrial Group ("Industrial Group"), an ad hoc group of industrial customers;[3] on April 17, 2024, by the Sierra Club ("Sierra Club"); on April 26, 2024, by River Ridge Property Owners' Association ("RRPOA"); on May 1, 2024, by the Kroger Co. ("Kroger"); on May 7, 2024, by Blocke, LLC ("Blocke"); on May 20, 2024, by Walmart Inc. ("Walmart"); on June 6, 2024, by Steel Dynamics, Inc. ("SDI") and the Rolls-Royce Corporation ("Rolls-Royce"); on June 27, 2024, by the City of Westfield, Indiana ("Westfield"); and on July 30, 2024, by River Ridge Development Authority ("River Ridge") (collectively, the "Intervenors"), each of which was granted permission to intervene through a Docket Entry.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was conducted on June 27, 2024, in Fishers, Indiana, which is the largest municipality in Duke's service area. The Commission conducted additional field hearings in Terre Haute on June 4, 2024, Bloomington on June 20, 2024, and New Albany on August 8, 2024. During the public field hearings, members of the public provided oral and/or written testimony in this Cause.

On July 11, 2024, the OUCC prefiled its respective direct testimony and attachments. The OUCC's prefiled evidence included testimony and attachments from the following witnesses:

- Michael D. Eckert, Director of the OUCC'S Electric Division
- Mark E. Garrett, President of Garrett Group Consulting, Inc.

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2 On August 8, 2024, Duke filed its Notice of Substitution of Witness and Adoption of Testimony notifying the Commission that Brian T. Liggett was adopting Harley McCorkle's direct testimony prefiled on April 4, 2024. On August 23, 2024, Duke filed its Second Submission of Revised Testimony and Witness Substitution.

3 The Industrial Group consists of Arconic, Inc.; Cargill; Elanco; Evonik; General Motors LLC; Harrison Steel Castings Co.; Haynes International, Inc.; International Paper Co.; Stellantis, Subaru of Indiana Automotive Inc.; USG Corporation. We note Primient was listed as a member of the Industrial Group in the Industrial Group's April 12, 2024 Petition to Intervene, but was not listed as a member in the Industrial Group's July 16, 2024 and July 24, 2024 amendments to its membership list).

- Kaleb G. Lantrip, OUCC Senior Utility Analyst
- Brian R. Latham, OUCC Utility Analyst
- Cynthia M. Armstrong, Assistant Director of the OUCC's Electric Division
- Brian A Wright, OUCC Utility Analyst II
- Roopali Sanka, OUCC Utility Analyst
- David J. Garrett, Managing Member of Resolve Utility Consulting PLLC
- John W. Hanks, OUCC Utility Analyst
- Dr. David E. Dismukes, Consulting Economist with Acadian Consulting Group

The OUCC also prefiled written consumer comments pertaining to this Cause, which were admitted as Public's Exhibit Nos. 12, 13, and 14.

On July 11, 2024, Nucor prefiled the testimony of Dr. Jay Zarnikau, an independent consultant who provides consulting services to clients on issues related to electricity rate design and regulatory policy.

On July 11, 2024, the CAC prefiled the testimony and attachments from the following witnesses:[4]

- Benjamin Inskeep, Program Director at CAC
- Dr. J. Richard McCann, Partner with M.Cubed
- Dr. Indra Frank, Coal Ash Advisor for the Hoosier Environmental Council

The CAC supplemented this evidence on July 16, 2024 with the testimony and attachments of Devi Glick, Senior Principal at Synapse Energy Economics, Inc.

The Industrial Group's prefiled case-in-chief, also filed on July 11, 2024, included testimony and attachments from the following witnesses:[5]

- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc.
- Brian C. Andrews, Principal, Brubaker & Associates, Inc.
- Brian C. Collins, Managing Principal, Brubaker & Associates, Inc.

On July 11, 2024, Kroger prefiled testimony of Justin Bieber, Principal for Energy Strategies, LLC.

On July 11, 2024, Walmart prefiled testimony of Lisa V. Perry, Director, Utility Partnerships – Regulatory for Walmart.

On July 11, 2024, Rolls-Royce prefiled testimony of Warren White, Senior Vice President of Assembly & Test, US Defence at Rolls-Royce.

4 On August 12, 2024, the CAC prefiled corrections to witness Inskeep's testimony.
5 The Industrial Group prefiled corrections to Mr. Gorman's testimony on August 21 and August 27, 2024, and to Mr. Andrews' testimony on August 26, 2024.

On July 17, 2024, RRPOA prefiled testimony of Josh Staten, Senior Director – Business Development and Real Estate for River Ridge and Marc A. Hildebrand, Chief Director – Engineering and Operations at River Ridge Commerce Center.

On July 24, 2024, Sierra Club prefiled testimony of Tyler Comings, Principal Economist at Applied Economics Clinic.[6]

Wabash Valley, Blocke, SDI, and River Ridge did not prefile evidence in this Cause.

On August 8, 2024, Duke prefiled rebuttal testimony, exhibits, and workpapers for the following witnesses:

- Pinegar,
- Graft,[7]
- Sieferman,
- Lilly,
- Diaz,
- Flick,
- Rimal,
- McKenzie,
- Kopp,
- Spanos,
- Riley,
- Caldwell,
- Luke,
- Hoeflich,
- Hill,
- Swez,
- Verderame,
- Colley
- Bauer and
- Patrick O'Connor, Lead Quantitative Analyst for Duke Energy Carolinas, LLC.

The Company prefiled an updated revenue requirement model on August 8, 2024.

On August 8, 2024, the OUCC filed cross-answering testimony and exhibits of witness Dismukes; the Industrial Group filed cross-answering testimony and exhibits of witness Collins; Nucor prefiled the cross-answering testimony of witness Zarnikau; and CAC prefiled cross-answering testimony of witness Inskeep.

The Presiding Officers issued a Docket Entry requesting additional information from Duke on August 21, 2024, to which the Company filed its response on August 23, 2024.

6 On August 22, 2024, Sierra Club prefiled corrections to witness Comings' testimony.
7 On August 23, 2024, Duke prefiled corrections to Ms. Graft's rebuttal testimony.

The Commission held an evidentiary hearing in this Cause which commenced on August 29, 2024, at 9:30 a.m. and concluded on September 5, 2024, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke, the OUCC, and Intervenors were present and participated through counsel. The parties' prefiled testimony and exhibits were admitted into the record without objection. In accordance with Ind. Code § 8-1-1-8.1 and the Commission's General Administrative Order 2024-02, a live stream transmission of the evidentiary hearing was available online through the Commission's website.

Having considered all the evidence presented in this proceeding, based on the applicable law and evidence, the Commission now finds:

1. Notice and Jurisdiction. Due, legal, and timely notice of the filing of the Petition in this Cause was given and published by Duke as required. Proper and timely notice was given by Duke to its customers summarizing the nature and extent of the proposed changes in its retail rates and charges for electric service. Due, legal, and timely notice of all public hearings in this Cause were given and published as required by law. Duke is a public utility as defined in Indiana Code § 8-1-2-1(a). Pursuant to Ind. Code §§ 8-1-2-42 and 8-1-2-42.7, the Commission has jurisdiction over Duke's rates and charges for utility service. Therefore, this Commission has jurisdiction over Duke and the subject matter of this proceeding.

2. Duke's Corporate Status. Duke is an Indiana limited liability corporation with its principal office at 1000 East Main Street, Plainfield, Indiana 46168. It has the corporate power and authority to engage, and is engaged, in the business of supplying electric utility service to the public in the State of Indiana. Duke is a wholly-owned subsidiary of Duke Holdco, LLC.

3. Existing Rates. Duke's existing retail rates in Indiana were established pursuant to the Commission's Order in Cause No. 45253, dated June 29, 2020. Those basic rates and charges remain in effect today, as modified by the reduction in rates produced by Indiana's repeal of the utility receipts tax, as well as the Commission's Order on Remand in Cause No. 45253, dated April 12, 2023, and various subsequent riders approved by the Commission over time that adjust Duke's rates for service to timely recover changes in certain costs associated with the provision of service.

4. Test Year and Rate Base Cutoff Dates. As authorized by Ind. Code § 8-1-2-42.7(d), Duke proposed a forward-looking test period determined on the basis of projected data, with the test year used for determining Duke's projected operating revenues, expenses and operating income being the 12-month period ending December 31, 2025 (the "Forward-Looking Test Period"). The historic base period is the 12-month period ending August 31, 2023.

Duke proposed to implement the requested base revenue increase in two steps on a phased-in basis. The cutoff date for Step 1 is December 31, 2025, except that the base rate will include the actual net plant in service, actual capital structure, and associated annualized depreciation expense as of June 30, 2024, and the 2025 forecasted amounts for regulatory assets, inventories, and prepaid pension asset. For Step 2, the cutoff date is also December 31, 2025, except that the base rate will include a credit for the difference in revenue requirements using the capital structure and the lesser of forecasted net utility plant in service and actual net utility plant in service on December 31, 2025, and associated annualized depreciation expense.

5. **Duke's Requested Relief.** In its Petition, Duke sought Commission approval of an overall increase in rates and charges for electric service that would produce additional revenues of approximately $491,537,000 in two steps, which would reflect an overall revenue increase of 16.20%. This overall revenue increase is comprised of a Step 1 increase of approximately $355.4 million, representing an approximate 12% increase, and a Step 2 increase of approximately $136.1 million, representing an approximate 4% increase.

As detailed in Duke's case-in-chief, Duke also requested Commission approval of a new schedule of rates and charges applicable to electric utility service, approval of new depreciation accrual rates, as well as regulatory asset treatment upon the retirement of Duke's last coal-fired steam generation plant. Duke further requested approval of one substantive change to its FAC rider to track its actual coal inventory balance. Further, the Company sought authority to defer expenses associated with an upcoming CCS study to be conducted for Edwardsport, as well as authority to defer to a regulatory asset costs incurred by the Company to achieve organizational savings. Finally, the Company sought authority to defer to a regulatory asset or liability, as applicable, all calculated income tax differences resulting from future changes in income tax rates until the effect of the income tax rate change can be fully reflected in the Company's rates.

6. **Opposition, Rebuttal, and Cross-Answering.** The OUCC and Intervenors disputed several components of Duke's filing, including challenging depreciation and amortization expenses, operating revenues, rate of return, operating and maintenance ("O&M") expenses, tariff changes, cost of service allocations, and rate design. The extent to which these parties disagreed with each other is shown in their cross-answering testimony. The extent to which Duke disagreed with the OUCC and Intervenors was addressed in the Company's rebuttal evidence.

7. **Field Hearings and Customer Comments.** As noted above, the Commission conducted field hearings in this Cause on June 4, 2024 in Terre Haute, June 20, 2024 in Bloomington, June 27, 2024 in Fishers, and August 8, 2024 in New Albany. Approximately 114 individuals testified at these field hearings, during which additional written comments were admitted into the record.

8. **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.

We considered reliability, resiliency, and stability issues, such as through our determinations regarding vegetation management, Edwardsport, and economic development needs. We additionally considered the environmental sustainability pillar. On this point, Ind. Code § 8-1-2-0.6 requires our consideration to include the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation. Such issues were a part of our consideration of the proposal to convert Edwardsport to operate solely on natural gas. Environmental regulations were central to the very basis of Duke's requested coal combustion residual ("CCR") cost recovery.

Pursuant to Ind. Code § 8-1-2-0.6, our analysis must include a consideration of the affordability of Duke's rates, as well as the competitiveness of those rates, in making our determinations and balancing this final pillar. As noted above, "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 (IURC Feb. 2, 2024). This difficulty is particularly present in the current Cause as Duke serves approximately 900,000 customers located in 69 counties.

Our affordability analysis included evidence from the field hearings held in this Cause as well as evidence presented by the parties. For example, we heard and considered the real life impacts that people described to us that Duke's proposed rate increase would have upon them, their families, and their communities. We listened to the effects that a rate increase would have on local governments, school corporations, and businesses. We also considered affordability issues directly impacting individual parties or their constituents. We analyzed the largest drivers that impact affordability in rate cases; namely, return on equity ("ROE"), depreciation methodology, the total revenue requirement, and the allocation of the revenue requirement. We considered the impact rates would have on economic development. We considered Duke's proposed process to phase in its rates.

9. Duke's Rate Base.

A. Utility Plant in Service Issues. The Company proposed six pro forma adjustments to its forecasted utility plant in service in its case-in-chief as set forth on Petitioner's Exhibit 26, Attachment 26-C, Schedule RB2. The only adjustment in dispute is Petitioner's adjustment for its new proposed depreciation accrual rates, which is addressed later in this Order. Otherwise, we find all pro forma adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

Further, the Company's forecasted net plant-in-service was largely uncontested, apart from certain parties taking issue with two items: the Cayuga landfill cell and the Company's Targeted

Economic Development ("TED") projects. We will address these issues first before turning to other rate base-related issues.

i. Duke Case-in-Chief. In his direct testimony, Company witness Hill described the status of the CCR units at Cayuga, including the ongoing Cayuga-related capital projects and costs. Mr. Hill described the Test Period CCR Power Production Capital Forecast to include Cayuga station costs to begin construction of cell 3 of the RWS II landfill to support disposal of production CCR. Further, as described in Company witness Abbott's testimony, the Company's 2024 and 2025 forecasted capital expenditures included approximately $6.7 million and $49.7 million, respectively, for transmission TED projects that the Company has not yet identified but anticipates a need. Regarding the unidentified TED projects, Mr. Abbott testified that these projects enable Duke to attract new business to its service territory. Mr. Abbott added that although the utility has not identified the TED projects, the Company anticipates economic development activity will continue at a high level, such that additional TED projects will be forthcoming.

ii. CAC Case-in-Chief. Mr. Inskeep recommended that the Commission deny the Company's request to include unidentified TED projects in its 2024 and 2025 forecast at this time. Mr. Inskeep testified these unidentified projects do not have costs that are known and measurable, and it is inappropriate and premature to approve recovery of tens of millions of dollars in projects that have not been identified, described, budgeted, or evaluated.

iii. OUCC Case-in-Chief. OUCC witness Armstrong objected to including the construction costs associated with the Cayuga Landfill Cell in rate base because the project will not be complete and in service until 2026, which is after the test year. She testified that since Duke cannot begin disposing CCR into the landfill cell until the cell is complete and receives certification from the Indiana Department of Environmental Management ("IDEM") that it meets all the operating permit conditions, the Cayuga Landfill Cell will not be used and useful for providing electric service before the test year ends. She recommended the capital expenditures associated with the Cayuga Landfill Cell be removed from the forecasted test-year rate base, resulting in a $1,862,074 rate base reduction.

iv. Duke Rebuttal. Ms. Lilly testified that the Company's rate base forecast does not include the Cayuga landfill cell project because this project is not anticipated to be in service by the end of the test year. As such, Ms. Lilly asserted no adjustment was necessary based upon Ms. Armstrong's recommendation.

Regarding the TED projects issue, Mr. Pinegar testified the Company plans for forecasted growth in its economic development efforts, and this approach allows the Company to remain responsive to potential economic growth while making infrastructure investments prudently. Mr. Pinegar explained that future TED projects will be evaluated on their individual merits in the context of an official docketed proceeding before the Commission and will also be reviewed by the Indiana Economic Development Corporation.

v. Commission Discussion and Findings. The Cayuga Landfill Cell 3 is not anticipated to be used and useful by the end of the test year; therefore, its capital costs associated with the Cayuga Landfill Cell should not be included in Step 1 or Step 2 rate base. To the extent Duke has included construction costs for the Cayuga Landfill Cell in rate base, we find they should be removed.

As to the issues Mr. Inskeep raised regarding the unidentified TED Projects, we believe it is reasonable for the Company to include a projection of investment in its forecast to support anticipated, but not yet identified, economic development projects. The record demonstrates the significant economic activity the Company supported in its service territory in 2023 - creating over 4,500 jobs and generating $6.4 billion in capital investment in 2023 and the Company anticipates economic development activity will continue at a high level and that additional TED projects will be forthcoming. It is often difficult to predict when an economic development opportunity will arise and, as Mr. Abbott acknowledges, these projects typically have very tight timelines. The Company must have capital available to meet these demands and we agree with Mr. Pinegar that this approach will allow the Company to remain responsive to potential economic growth while making infrastructure investments prudently. Duke's approach will still require the utility to obtain Commission approval through a subsequent proceeding to undertake such TED Projects. We also note that the costs associated with the TED Projects which are included in the test year rate base are not to be tracked through the TDSIC proceeding, but that amounts in excess of the amount included in rate base may be tracked through the TDSIC proceeding (subject to Commission approval of the increased cost). For all of these reasons, we find the forecasted capital investment associated with such projects is reasonable and should be approved.

B. Edwardsport Integrated Gasification Combined Cycle ("IGCC") Plant.

i. Edwardsport Transition to Natural Gas.

a. Duke Case-in-Chief. Mr. Pinegar described Duke's generation assets in his case-in-chief testimony. He testified that the Company maintains a reliable and diverse portfolio of generation assets to provide service to its customers, including approximately 600 megawatts ("MW") of syngas generation at Edwardsport Generating Station.

b. CAC Case-in-Chief. CAC witness Glick testified generally regarding Duke's coal generation fleet and its fuel procurement strategies. Specifically regarding Edwardsport, Ms. Glick contended the plant has operated with low capacity factors and has not operated reliably, and these trends are likely to continue with non-fuel O&M costs that have ranged over the years 2020 through 2023 at very high levels compared to industry averages, especially considering that the plant is only around a decade old. Ms. Glick further testified Edwardsport has been expensive to maintain and will continue to be so. As such, Ms. Glick recommended the Company should plan to operate Edwardsport on gas and operate on coal only when needed to manage coal oversupply. She further recommended the Commission should advise Duke that in future FAC dockets, it will disallow recovery of fuel costs above what it would cost to operate Edwardsport on the lowest operating cost resource (which she claims is generally gas) unless there is documentation showing that the decision was prudently incurred to manage fuel supply.

c. Industrial Group Case-in-Chief. Mr. Gorman testified that Duke's evidence, including its 2021 integrated resource plan ("IRP"), demonstrates that continuing to operate Edwardsport as an IGCC on syngas rather than convert it to natural gas is uneconomic. Mr. Gorman recommended a disallowance of $63.6 million from Duke's revenue requirement, which was calculated based on Duke's non-fuel O&M expense (exclusive of major outage costs) and Duke's estimate of non-fuel O&M to operate Edwardsport on natural gas only, based on the projected costs of such operations in Duke's 2021 IRP.

Mr. Gorman testified that Duke's IRP analysis found that immediate conversion of Edwardsport to a natural gas combined cycle unit is more economic than continued operation on syngas and this was true for every optimized portfolio of Duke's 2021 IRP. He asserted the only reason the Company's preferred portfolio kept Edwardsport operating as an IGCC on syngas through the end of 2034 is because Duke hard-keyed this result.

Mr. Gorman challenged Duke's explanation in response to a Data Request that the reason the Company hard-keyed continued operations on syngas was because of the Commission's Order in the last rate case. He explained that the Commission's prior Order did not mandate continued operations as an IGCC, and that there are numerous key differences between the last base rate case and the present one warranting an updated assessment of Edwardsport's operations, explaining:

- At the time of Duke's last rate case, only the 2018 IRP had been conducted, and that IRP had not evaluated operating Edwardsport on natural gas, but instead simply hard-keyed the outcome for continued syngas operation. It was not until the 2021 IRP wherein the possibility of operating Edwardsport on syngas only was evaluated quantitatively, and that evaluation demonstrated that continued operation of Edwardsport on syngas was unjustified.

- In the last rate case, Duke had relied on the newness of Edwardsport as a basis for continued operation on syngas, including that the plant had not yet completed its full maintenance cycle. This newness argument can no longer be made. Since the 2020 rate case, Edwardsport has operated for an additional four years, and it underwent its first full maintenance cycle. Duke has acknowledged that Edwardsport's performance "has achieved a relatively steady state."

- Duke testified in its last rate case that Edwardsport's capacity on syngas is 618 MW, but the Company now acknowledges that its syngas capacity only reaches 578 MW.

- Duke no longer claims that tax incentives support continued operations on syngas.

Mr. Gorman testified that the cost of operating Edwardsport on syngas is exorbitant. He explained that according to Federal Energy Regulatory Commission ("FERC") Form 1 data, the 5-year average non-fuel production cost for Edwardsport is $154.29 per kW of capacity (based on a capacity of 618 MW). He noted this is over ten times more expensive than the $14.80 average costs of other similarly situated natural gas combined cycle plants. He said it is also more than five times more expensive than the next-highest natural gas plant. Moreover, Mr. Gorman also pointed out that the cost to operate Edwardsport on syngas is also significantly higher than the cost to operate Edwardsport on natural gas by Duke's own estimates. He stated that in its 2021 IRP, Duke estimated that the average annual cost to operate Edwardsport on syngas was $92 million, whereas the cost to operate it on natural gas was only $26 million.

Mr. Gorman also testified that the ongoing higher capital investment needed to operate Edwardsport as an IGCC also supports conversion to natural gas operations. He stated FERC Form 1 data shows that the annual capital improvement costs at Edwardsport over the last two years were more than four times the capital costs at similarly situated natural gas combined cycle plants. He argued this is true even though the years considered (2022 and 2023) did not include the annual recurring $6.63 million amortization of the seven-year major outage costs (which occurred in 2020). He pointed out that altogether, Duke has spent $499 million in post-in-service capital costs ("PISCC") since Duke declared Edwardsport in service in 2013.

Mr. Gorman also testified that Edwardsport can be dispatched more economically when operated on natural gas. When operating Edwardsport on natural gas, Duke offers Edwardsport into the Midcontinent Independent System Operator ("MISO") as a must-run unit, which means that Edwardsport operates even if it is more expensive than other lower-cost generation resource options. However, if Edwardsport is operated on natural gas, Duke has the option to offer it into MISO on an economic basis.

Mr. Gorman testified that if Edwardsport operates on natural gas only, its capacity is reduced from 555 MW - 578 MW on syngas to 451 MW - 541 MW on natural gas, a reduction that is likely offset by the potential savings of non-fuel O&M and PISCC. Moreover, if Edwardsport were optimized to permanently function on natural gas only, Duke estimates that the plant would actually gain capacity, up to 586 MW.

Finally, Mr. Gorman testified that operating Edwardsport on natural gas would reduce carbon dioxide emissions by more than 50%, sulfur dioxide emissions by almost 90%, and nitrogen oxide emissions would be almost eliminated.

d. **<u>Sierra Club Case-in-Chief</u>.** Sierra Club witness Comings testified the Company should have ceased operating Edwardsport on coal because the plant is exorbitantly expensive to operate, has diminished capacity value, and the Company previously found that converting the plant to natural gas in 2023 was cost-optimal in its 2021 IRP, in all scenarios that allowed for cost-optimization. Mr. Comings offered three main points in support of his position that Duke's syngas O&M costs should be disallowed and the plant should be operated on gas only.

First, in every modeling run for which Duke allowed cost optimization, the lowest-cost option showed that conversion to gas would save customers money. In the 2021 IRP, under all scenarios in which the model selected the lowest-cost plan—reference case without carbon regulation, reference case with carbon regulation, high gas prices, and low gas prices—the model chose conversion of Edwardsport to gas-only operations.

Second, Mr. Comings further testified that Edwardsport's fixed costs are exorbitantly high—including O&M and capital—compared to other generators, and that Duke could build brand new thermal resources for a lower cost than simply maintaining Edwardsport on syngas. He said that since starting operations, the plant has incurred nearly $500 million in capital costs, in addition to its multi-billion dollar construction costs. As an example, Mr. Comings noted the Commission recently approved two new gas combustion turbines, totaling 460 MW of capacity, for Southern Indiana Gas and Electric Company, Inc. d/b/a CenterPoint Energy Indiana South ("CenterPoint") at a capital cost of $334 million. He stated that, in other words, Duke could build brand new peaking gas units with similar capacity to Edwardsport with just the ongoing capital expense for this plant that has been incurred in under ten years of operations. Mr. Comings also provided a supporting confidential comparison of the going-forward costs of Edwardsport and the MISO cost of new entry ("CONE") calculations.

Third, Mr. Comings argued that when operated on syngas, Edwardsport is Duke's least-flexible thermal resource. Instead of offering the plant for economic commitment into the MISO energy market, Duke designates Edwardsport as "must run," [8] meaning both that the plant is likely operating during many hours at an energy-market loss (i.e. customers would be better off with zero generation from Edwardsport) and that the plant is not eligible for "make whole" payments from MISO. He stated that for a more-flexible power plant, even if a plant is committed as "must run," MISO could dispatch the plant economically up and down to respond to changing market prices and conditions, but such dispatch flexibility is not available at Edwardsport because the economic minimum operation and maximum output are essentially the same. In other words, he noted, on syngas, Edwardsport operates regardless of market prices and with no operational flexibility. Mr. Comings recommended that because Edwardsport is incapable of operating outside of persistent must-run commitment on syngas, this is further reason to convert to permanent gas operation, as a gas-only plant would be more flexible in the MISO energy market.

e. <u>Duke Rebuttal</u>. On rebuttal, Company witness Luke responded to the parties' criticisms of Edwardsport and disagreed with the parties' recommendations to run Edwardsport on natural gas. Mr. Luke explained the importance of maintaining safe, stable, reliable, and environmentally compliant operations of its generating fleet. He explained why Duke believes diversity in the Company's generation options is increasingly vital, especially given the recent changes in the energy and capacity markets. Mr. Luke testified that having flexibility to operate Edwardsport on both coal and natural gas provides benefits to the Company and its customers in a variety of situations. Mr. Luke explained that as MISO transitions to an increasing penetration of renewable resources, the degree of volatility in the energy market is increasing, which requires increasing flexibility in operations of thermal resources. He testified regarding the reliability and resiliency value of maintaining fuel inventory at coal plants relative to natural gas, as well as the reliability and resiliency value of being able to switch fuels at Edwardsport and run the plant on natural gas when circumstances warrant. Mr. Luke testified this flexibility positions Edwardsport as a key asset in Duke's diverse portfolio and allows the site to be available when others may not be available.

Mr. Swez testified that the Company offers Edwardsport into MISO with a commitment status of must run when its gasifiers are operating for the following reasons:

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[8] Mr. Comings confidentially quantified how often Dukes designates Edwardsport as "must run."

- Cycling Edwardsport station on and off would likely cause the station's equivalent forced outage rate to increase, causing both a lower capacity value for the MISO capacity auction as well as less energy value in the MISO energy markets.

- The station's gasifiers and other gasification systems have an approximate 14-day cycle time (operating to ambient and then back to operating). Thus, if the gasifiers are brought off-line, the unit would be unavailable on coal for this period.

- De-committing Edwardsport gasifiers for long periods of time would cause loss of essential personnel.

- Switching the station to natural gas for short periods of time may often appear to be a better economic decision than it really is. At times, the daily profit and loss analysis that the Company uses to inform its commitment offer does suggest cycling the station to natural gas for short periods of time. However, this can be misleading, since the analysis doesn't include the fact that gasification systems, such as the air separation unit, cannot be turned off for short periods of time if the unit is switched over to natural gas, continuing to consume auxiliary energy and not allowing for the anticipated savings. The Edwardsport natural gas unit on the Company's daily analysis assumes that the gasifiers are totally shut down which for a short shutdown is an inaccurate assumption.

- Currently, the Company has two contracts for firm natural gas on Midwestern pipeline, the gas pipeline that serves Edwardsport, Wheatland, and Vermillion Stations. These contracts, for 52,800 dekatherm ("dth")/day and 28,000 dth/day, are only roughly enough to serve the natural gas needs for Edwardsport Station on natural gas. (Edwardsport would burn 96,000 dth/day assuming an 8,000 British Thermal Unit/ kilowatt-hour ("kWh") heat rate and 500 MW generation output for each hour of the day). Utilization of Edwardsport solely on natural gas would reduce the ability for this contract to be used for Wheatland and Vermillion stations. Although the Company has the ability to buy delivered gas from third-party suppliers in addition to transporting on the Midwestern Firm Transport to Wheatland, Edwardsport and Vermillion Stations, if Edwardsport were to switch to 100% natural gas, it would make third-party supply scarcer and most likely more expensive when Wheatland and Vermillion also are running.

- Although the Company is not predicting a fundamental return to higher gas prices, retirement or moth balling of the Edwardsport gasifiers eliminates any option to buy coal in the event that natural gas prices increase. Operating solely on natural gas could essentially become a permanent decision, losing the diversity value of coal, and in addition the Company would lose valuable gasification expertise in the interim.

- Edwardsport is permitted to operate on coal as a primary fuel and natural gas as a secondary fuel. The air permits do not really contemplate operating Edwardsport on natural gas as a primary fuel over extended durations.

Likewise, Mr. Luke testified that regularly switching primary fuels at Edwardsport "would be very difficult." He explained that to really maximize the variable cost benefits:

> it would involve completely shutting down the gasifiers and other supporting gasification systems. Otherwise, those systems would be sitting in standby, using substantial auxiliary power to the detriment of the output and efficiency of the unit on natural gas. Completely shutting those systems down and turning them back on, however, is a multi-week-long process. It can take up to fourteen days of turnaround if all of the gasification systems are allowed to reach ambient conditions (i.e., gasifiers fully cooled down, and the cryogenic components of the air separation unit fully warmed up), requiring a complete re-start of the plant. This makes it operationally difficult, time consuming, and costly to switch fuels in response to short-term natural gas price signals in an attempt to capture benefits for customers.

Pet. Ex. 40 at 21.

Further, Mr. Luke disagreed with the parties' positions that Edwardsport has diminished capacity and is not operating reliably. He asserted that the use of coal plants is changing as they spend more time operating than they have historically, due to the increased use of intermittent resources, but at lower output levels so they are ready to raise output at any time. As such, he said the units' service factors have increased over the past few years while the units' capacity factors have decreased. Further, he noted the 2023 equivalent forced outage rate on the Company's coal units overall decreased by 48% from the period average. He further stated the units' service factors, another informative reliability metric (that is, the percentage of all available hours in which a plant operated), are increasing. Mr. Luke testified this indicates that while the total energy output of the coal fleet continues a slow decline, the importance of the service of the coal units to system reliability is increasing, as the units are spending more relative time on-line. He added that in 2022, the Edwardsport plant set a record of continuous grid generation for achieving a 363 consecutive day run during which time there were both planned and unplanned interruptions of gasification operations.

Ultimately, Mr. Luke testified that it would not be strategic to prematurely shut down the Company's ability to utilize coal at the units, which are important assets that could provide energy and capacity to customers for years to come and which are not easily replaced. Mr. Swez testified that early retirement of Edwardsport would likely force the Company to procure an additional 450 MW of bilateral purchases, to the extent that these purchases are available. He further testified that short-term operation on natural gas only would likely force the Company to procure an additional 40 MW of bilateral purchases, again to the extent that these are available, due to the units' required derate when operating solely on natural gas operation.

Mr. Luke opposed the parties' positions that the costs to operate Edwardsport on syngas fuel are too high compared to natural gas. He asserted these costs are not too high given Edwardsport's multifaceted value proposition to customers. Further, Mr. Luke testified that the dollar amounts the intervenors used to compare Edwardsport O&M costs running solely on what he described as "planning quality estimates" used as placeholder estimates from Duke's 2021 IRP, rather than "rate-case quality" estimates. He testified that while the estimates were sufficient for IRP modeling purposes at the time, the estimates used by the intervenors lacked funding for an operational plan that would support safely, reliably, and effectively operating the facility. Further, Mr. Luke testified the O&M costs proposed by the intervenors do not contemplate all the elements needed to be considered for operating Edwardsport solely on natural gas fuel. Finally, Mr. Luke testified the parties' focus on the expense of operating the coal units does not acknowledge that replacement resources have their own costs and risks.

Mr. Luke also responded to the parties' positions that the Company should have switched to operating Edwardsport on natural gas based on the 2021 IRP. Mr. Luke explained that the Company's IRP analysis utilizes multiple modeling scenarios resulting in various outcomes, including optimized portfolios, referenced by the intervenors, and the preferred portfolio. He explained the optimized portfolio only considers economic factors, rather than including factors that are required for a long-term balanced generation portfolio, such as fuel flexibility, generation capacity, and operational resiliency. Mr. Luke stated the optimized portfolios are only used to inform the preferred portfolio. He noted the optimized portfolio does not take into account the many other factors that are required for a long-term balanced generation portfolio, such as fuel flexibility, generation capacity, and operational resiliency. Mr. Luke testified that based on his understanding, the Company's preferred portfolio in the 2021 IRP did not include an immediate and permanent fuel switch at Edwardsport and that the Company continues to assess this possibility in its current IRP modeling process.

Ultimately, Mr. Luke testified the decision to switch Edwardsport to natural gas requires careful consideration, as the benefits to Duke when it comes to reliability and resiliency of its generation supply, including Edwardsport as a dual fuel capable unit, are difficult to completely overlook – especially given that the Company is already assessing replacing its other, older coal units with cleaner generation in its IRP.

f. Additional Evidence Received at Hearing. During the hearing, Mr. Luke acknowledged that the cost to run Edwardsport on natural gas was taken from Duke's own estimates. He stated it is more expensive to operate Edwardsport as an IGCC on syngas than on natural gas only. Mr. Luke stated that if Duke decided to convert Edwardsport to full-time gas use, it could avoid some anticipated future maintenance costs and specifically that non-fuel O&M cost at Edwardsport, which he estimated would be approximately $75 million lower in 2027 if Edwardsport converted to run only on gas. He stated that it is possible that Duke could avoid significant capital expenditures by converting to natural gas. Mr. Luke also admitted that if Edwardsport made a full conversion to natural gas, the gasifiers would not be needed. He admitted on cross-examinations that he was not familiar with how the 2024 forecast was developed.

The Industrial Group offered the entire narrative portion of the IRP, which was admitted as IG CX-9, demonstrating that the optimized portfolios did consider generation capacity and that determining generation capacity is one of the key outputs of the IRP.

Mr. Verderame explained that coal suppliers are struggling with finding labor and he discussed the limitations to coal suppliers' ability to attract labor. Mr. Verderame opined that this issue will become increasingly exacerbated as time continues into the future, affecting the whole coal supply chain. Mr. Verderame testified that Duke's ability to operate Edwardsport on coal or gas is one measure to address coal inventories. He stated that this approach is limited in scope to address an undersupplied condition. He questioned the longevity of the fuel switching approach, how long Duke can do it, and how big a problem Duke can really solve with this approach.

CAC Exhibit CX-3 indicates that Edwardsport's service factor was 0% in February 2024, 0% in March 2024, and 6.8% in April 2024.

g. <u>Commission Discussion and Findings</u>. We note at the outset of our findings that the issues the intervenors raised in this proceeding with respect to Edwardsport are the same issues this Commission has addressed in prior proceedings, including in Duke's last base rate case, Cause No. 45253. In Cause No. 45253, we found that continued operations primarily on coal is reasonable for Edwardsport. For the reasons described herein, we do not believe any changed circumstances warrant a different finding here.

The Industrial Group and Sierra Club argued that the differences between Duke's last base rate case and this proceeding require a different conclusion. The main difference the parties cite is the availability of the Company's 2021 IRP results, particularly the Company's optimized portfolios, which they claim supports a transition of Edwardsport's operations to natural gas. The parties contend Duke ignored this result and instead hard-keyed continued operation of Edwardsport as an IGCC into its preferred portfolio in the 2021 IRP.

On rebuttal, Company witness Luke explained that the optimized portfolios the intervenors relied on are different than the Company's preferred portfolio. He explained the optimized portfolios only consider the economics of a specific modeling scenario and do not account for the many other factors that are required for a long-term balanced generation portfolio. As such, Mr. Luke explained the optimized portfolios are only used to inform the preferred portfolio.

We disagree with Industrial Group and Sierra Club that the Company's 2021 IRP results support Edwardsport's immediate conversion to natural gas. As Mr. Luke explained on rebuttal, the intervenors' position relies on the results from the 2021 IRP optimized portfolios, which the record demonstrates only consider economics and do not consider other factors required for a long-term balanced generation portfolio. In contrast, the preferred portfolio considers these factors and many others in informing the Company's decisions on how to use existing and future resources to meet customer demand. In fact, as the Company's 2021 IRP makes clear, the Company reviewed a variety of metrics, both qualitative and quantitative in deciding upon its preferred portfolio that included continued operation of Edwardsport as an IGCC plant. The Company's selection criteria included metrics on reliability, such as limiting reliance on market purchases; resiliency and stability considerations, such as the diversity of the portfolio and its executability; affordability; environmental sustainability, and flexibility. In doing so, the Company explained that many qualitative factors supported the continued operation of Edwardsport IGCC on coal, including:

- Edwardsport is Duke's newest and cleanest coal plant, which has a trajectory of improving operations and lowering costs.

- The need for diverse fuel sources as Duke transitions to cleaner energy and Edwardsport provides resource diversity in the longer term, potential options for carbon capture utilization and storage, and reliability benefits of dispatchable, onsite fuel source.
- Uncertainty about carbon prices, gas prices and gas availability, new technology availability and timing, and the need for reliability in the MISO region (from an energy and capacity perspective).

As a result, the Company's 2021 preferred portfolio did not include an immediate and permanent fuel switch at Edwardsport, and thus we find the Company's 2021 IRP process does not support the conclusion that Duke should transition Edwardsport to natural gas.

Thus, we disagree with the Industrial Group and Sierra Club that the 2021 IRP results support the Commission reaching a different conclusion on Edwardsport from what we previously concluded in the Order in Cause No. 45253. What has changed since that proceeding, however, is the Legislature's passage of HEA 1007 (2023) and the requirement that the Commission consider and evaluate the Five Pillars—reliability, resiliency, stability, environmental sustainability, and affordability—in making our determinations in this proceeding.

Further, the Company is currently in the middle of its 2024 IRP process and is considering these same issues in the context of that process. As such, it would be premature for the Company or the Commission to make any determinations in this proceeding regarding a permanent fuel switch at Edwardsport until that process has had an opportunity to play out.

The crux of the intervenors' argument is that in doing a comparison of the costs to operate Edwardsport on syngas versus natural gas, it is significantly cheaper to operate Edwardsport on natural gas. Thus, their view is that the pillar of affordability would be served by transitioning Edwardsport solely to natural gas. On rebuttal, Mr. Luke asserted that in running their comparisons, the intervenors' used planning-level quality estimates that did not consider all the costs needed for operating Edwardsport solely on natural gas fuel. Thus, Mr. Luke questioned the reasonableness of the intervenors' estimates and their ultimate calculations.

Additionally, the intervenors' main focus is on the economic value of operating Edwardsport as an IGCC versus a natural gas plant, and they fail to consider some of the non-economic value of continued operation of the plant on syngas. The Company demonstrated on rebuttal the multifaceted value operating Edwardsport as an IGCC offers to customers, and thus a comparison of only the costs to operate the plant does not paint an accurate picture of the overall value operating the plant as an IGCC provides to the Company and its customers. Further, as Mr. Luke noted on rebuttal, the intervenors' recommendations to transition Edwardsport do not consider that replacement resources have their own costs and risks.

Turning to the pillars of reliability, resiliency and stability, the Company demonstrated these pillars are best served by maintaining Edwardsport as an IGCC. The record demonstrates that having the flexibility to operate Edwardsport on both coal and natural gas provides significant benefit to the Company and its customers in terms of reliability and resiliency. Such flexibility is critically important given market uncertainty and the need for reliability in the MISO region. Duke discussed these benefits at length in Company witness Luke's rebuttal testimony and demonstrated why this flexibility is valuable to the Company, its customers, and the overall resiliency of the system. In addition to fuel switching, there are other flexibility benefits associated with Edwardsport, and this flexibility allowed Edwardsport in 2022 to set a record of continuous grid generation for achieving a 363 consecutive day run, during which time there were both planned and unplanned interruptions of gasification operations. The Commission agrees there is substantial value in maintaining Edwardsport as an IGCC and the flexibility it provides. We have consistently recognized the importance of generation resource diversity in prior proceedings, including in Duke's last rate case.

Further, the record demonstrates that early retirement of Edwardsport or a permanent switch to natural gas would likely force the Company to be short on its capacity positions in the near-term and require the Company to procure additional capacity. A transition to natural gas operations at Edwardsport could reduce Edwardsport's capacity by approximately 100 MW immediately. The increased Company short position exposes customers to increased market dependence and concurrent price volatility which create risk to affordability.

We disagree with the Industrial Group that Duke's capacity concerns are unfounded. The question is not whether Edwardsport can be immediately converted to permanent natural gas operations as soon as a final order is issued in this Cause, but whether Duke has satisfied its burden to show that it is entitled to an additional $64 million a year in what the Industrial Group deems to be excessive and unnecessary O&M costs for syngas operation. Our analysis is multi-pronged. We must look at short-term and long-term opportunities, costs, and needs and weigh those in light of the Five Pillars. In doing so, the immediate value of capacity in MISO and in Indiana weigh in favor of maintaining Edwardsport's current capacity offerings.

The Industrial Group also argued that operation on coal threatens reliability due to the "devolving" coal supply chain Company witness Verderame described at the hearing. We agree with Duke that while the long-term challenges in the coal supply chain are real, the most pressing reliability concern is the immediate loss of capacity from the premature and permanent conversion of Edwardsport to natural gas and the impact this would have on Indiana's electric grid.

The fact that Edwardsport runs on a local fuel source (Indiana coal) mitigates the coal-supply concerns raised by Mr. Gorman. That is, by relying on Indiana coal, the plant's fuel supply is largely insulated from transportation issues. Further, procuring coal from a local Indiana source also limits the impacts from natural disasters, pandemics, and political events that impact the price and availability of both coal and natural gas.

Further, while the ability to ramp up and down quickly is one type of flexibility, it is not the only aspect of flexibility which must be considered. We also acknowledge that operating the plant on natural gas would support environmental sustainability and reduce emissions. However, as noted, we must balance each of the Five Pillars, in reaching our decision.

Therefore, in balancing the pillar of affordability with the pillars of reliability, resiliency, and stability, we again find that Edwardsport's continued operations primarily on coal is reasonable. The fifth pillar of environmental sustainability is also supported by Edwardsport, which is one of Indiana's cleanest coal plants in terms of environmental emissions and has proven resilient in the face of new environmental regulations. Further, it presents an opportunity for balancing the value of continued fuel diversity with an improved emission footprint given the Company's ongoing evaluation of CCS technologies at Edwardsport, an issue which we address later in this section.

Having determined that Edwardsport's continued operations as an IGCC are reasonable, we will now address the specific arguments raised by the intervenors in the following sections. We address the parties' issues related to uneconomic dispatch and the Company's fuel procurement strategies in the FAC Issues section of the Order.

ii. Edwardsport Capital Investments. CAC witness Comings recommends the Commission open a subdocket to review the capital costs of the Edwardsport plant to identify those that could have been avoided if Duke had planned for gas conversion after its 2021 IRP. Industrial Group witnesses Gorman and Andrews suggest that the Company should be required to segregate the Edwardsport remaining net book value between gasification property needed just for operations on natural gas.

Both of these recommendations are based on the premise that the Company should have converted its Edwardsport plant to run on natural gas as soon as 2023. However, as recently as 2020, this Commission determined that continued operation primarily on coal was reasonable for Edwardsport, and that determination was supported further by the selection of Duke's 2021 IRP preferred portfolio. As discussed above, we continue to find that operations primarily on coal is reasonable for Edwardsport, and we reject the CAC and Industrial Group's recommendations with respect to the Edwardsport capital investments.

iii. Edwardsport O&M Costs. Regarding ongoing O&M costs at the Edwardsport plant, CAC witness Comings and Industrial Group witness Gorman both claim that the costs to operate Edwardsport on syngas are too high and recommend the Commission limit Duke's cost recovery in this proceeding to only those costs needed to operate Edwardsport on natural gas. Specifically, Mr. Comings recommends that only $22.2 million of test year O&M costs be recoverable in this case. Mr. Gorman recommends a disallowance of $63.6 million based on his calculation of the difference between operating the plant on syngas and the cost to operate solely on natural gas. Similarly, CAC witness Glick compares the annual O&M costs for Edwardsport to industry averages and argues that Edwardsport costs are too high. Ms. Glick does not recommend a specific dollar amount disallowance in this proceeding, but recommends the Company operate the plant primarily on natural gas moving forward, and that the Commission disallow recovery of fuel costs in future FAC proceedings above what it would cost to operate Edwardsport on the lowest operating cost resource unless there is documentation showing that the decision was prudently incurred to manage fuel supply.

As we discussed previously, Company witness Luke questioned the validity of the cost estimates the intervenors used for comparison purposes because the parties used planning-quality estimates from Duke's 2021 IRP that Mr. Luke testified did not contemplate all of the elements needed to be considered for operating Edwardsport solely on natural gas fuel. Further, Mr. Luke described at length in his rebuttal testimony the value Edwardsport provides to customers when operating on both coal and natural gas. Thus, as we discussed in the prior section, we do not believe a comparison solely of the economics associated with operating the plant on syngas versus natural gas, without weighing these other benefits, is appropriate.

Consistent with our findings in Cause No. 45253, we reject the recommendations of the Industrial Group and Sierra Club that only O&M costs associated with hypothetically running Edwardsport as a gas unit should be included in rates. We found in the previous section that continued operations primarily on coal is reasonable for Edwardsport, and, as such, find it reasonable to set a level of O&M in base rates on such operation. For this reason, we also reject CAC witness Glick's recommendations with respect to the plant's operations and future FAC proceedings.

We emphasize the importance of Duke continuing to improve the robustness of its analysis and discussion of the qualitative considerations in its IRP (and relevant docketed proceedings) with respect to the various operating options available at Edwardsport. The understanding of the performance of different resource portfolios across different circumstances accounting for seasonal operations at Edwardsport and other coal-fired units on the DEI system should evolve alongside the evolution of MISO markets and operations.

iv. Other Ratemaking Issues. Based on his contention that Edwardsport's syngas operations should be retired and the plant transitioned to run solely on natural gas, Industrial Group witness Gorman made a series of other accounting, financing and rate recovery recommendations in his testimony for what should occur after said retirement. Given our findings above regarding Edwardsport capital costs, we decline to adopt these recommendations. Additionally, Duke was issued a CPCN pursuant to Ind. Code ch. 8-1-8.8 for Edwardsport, and, therefore, Duke is afforded certain ratemaking protections for costs incurred in reliance on that CPCN.

C. Gibson Station ("Gibson") Retirements.

i. Duke Case-in-Chief. Mr. Luke provided an overview of Duke's generating fleet; Duke's operating philosophy for the fleet; and the fleet's historical operational performance against industry benchmarks. As part of this discussion, he noted that Duke plans to retire Gibson Units 1 and 2 in 2025 and Gibson Units 3 and 4 in 2031. He stated that Duke anticipates performing at least one more full normal maintenance cycle before the units' retirement.

ii. Sierra Club and CAC Case-in-Chief. Sierra Club witness Comings recommended that Gibson Units 1 and 2 should be considered for earlier retirement. He testified that all Gibson units are expected to have high forced outage rates, making them highly unreliable capacity resources. Mr. Comings noted that the Company is evaluating unit retirements at Gibson in its forthcoming IRP and recommended the Commission review capital costs at these units in a sub-docket to be established in this case to determine if any costs could be avoided if the units' retirement date is changed. Mr. Comings further testified the Company should identify capital spending that is avoidable with earlier retirement at these units in future rate cases. He recommended the Commission compel the Company to identify any avoidable spending ahead of time so that it can determine whether to include these costs in future rate cases. Similarly, CAC witness Glick argued that certain investments in Gibson Unit 5 could be avoidable if the units are retired earlier.

iii. <u>Duke Rebuttal and Cross-Examination Testimony</u>. On rebuttal, Company witness Luke explained that Gibson Units 1 and 2 are valuable assets used to provide energy and capacity for the Company's customers. He testified that the retirement dates for Gibson Units 1 and 2 are appropriate to meet the needs of the Company's customers. He further testified that from an operator's perspective, he sees no reason why Gibson Units 1 and 2 would be retired any earlier than currently anticipated, but the Company's IRP process is where these conversations should be had.

Mr. Luke also responded to the argument that certain costs could be reduced or eliminated if Gibson Units 1 and 2 are retired earlier. Mr. Luke explained that capital investments at these units are made in response to safety, environmental, regulatory, and reliability requirements, and such investments are evaluated and prioritized to maximize customer value considering the remaining life of the asset. With respect to Gibson Unit 5 specifically, he testified the currently identified investment in Gibson Unit 5 through the 2025 test year is prudent and necessary even if the unit would retire earlier than 2030. He further testified that critical components that are at the end of useful life must be replaced to maintain reliability, even if just a few years from potential retirement and the Company's customers still need these assets to perform until retired.

iv. <u>Commission Discussion and Findings</u>. Pursuant to the Commission's rules, Duke conducted an IRP process to evaluate the future of its generation portfolio. We agree with Mr. Luke that the Company must continue to make investments in coal plants, even those close to retirement, in order to respond to safety, environmental, regulatory, and reliability requirements, which is consistent with Ind. Code § 8-1-8.5-13(k). We also decline to establish a subdocket as Mr. Comings proposed and instead find that the IRP process offers a reasonable stakeholder process to address these issues. Thus, we decline to find that the investments in Gibson Unit 5 are inappropriate at this time.

D. <u>Fuel Inventory</u>. The Company proposes to include a representative balance of 45 days of coal inventory in rate base in this proceeding. While certain intervenors and the OUCC took issue with the Company's proposal to track the actual inventory balance in the Company's quarterly FAC filings, as well as with the Company's fuel procurement strategies in general, no party took issue with the Company's proposal to include 45 days coal inventory in rate base. In the Company's last base rate case, the Commission found the Company's forecasted coal inventory level of 45 days was reasonable, and we see no reason to deviate from that finding in this proceeding. As such, we find the Company's forecasted coal inventory level at 45 days is reasonable and should be included in the calculation of its rate base.

We address the parties' positions on the Company's fuel inventory tracker proposal and its fuel procurement practices generally, in the Fuel Inventory and the Fuel Cost Adjustment (Rider 60) sections below.

E. <u>Regulatory Assets</u>. Duke's Exhibit 26, Attachment 26-C, Schedule RB3 details the balances of the regulatory assets included in rate base and the Commission cause number approving deferral and/or recovery of each. Here, the only issue before us with respect to Duke's forecasted regulatory asset balance is with respect to the Company's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") regulatory asset.[9] We address this issue and the TDSIC Tracker (Rider 65) under the Rate Adjustment Mechanisms section of this Order. We otherwise find Duke's forecasted regulatory assets and regulatory asset balances are reasonable and are approved.

F. Materials and Supplies Inventory. Duke's forecasted materials and supplies ("M&S") inventory balance is set forth on Duke's Exhibit 26, Attachment 26-C, Schedule RB4. No party took issue with the Company's forecasted M&S inventory balance, and we find the forecasted amount is reasonable and is approved.

G. Prepaid Pension Asset.

i. Duke Case-in-Chief. The Company's prepaid pension asset balance in this proceeding is set forth on Schedule RB5 of Duke's revenue requirement model and updated revenue requirement model. Company witness Graft explained that the prepaid pension asset is defined as the cumulative amount of cash contributions to the pension trust fund in excess of the cumulative amount of accrued pension cost. She testified the Commission previously approved inclusion of the prepaid pension asset in the Company's rate base in Cause No. 45253. Ms. Graft testified the balance as of the end of the base period of $192,081,000 was adjusted for projected contributions and actuarial expense to arrive at the forecasted 2025 balance of $229,841,000.

ii. Industrial Group Case-in-Chief. Industrial Group witness Gorman recommended the Commission remove approximately $37.8 million (approximately $36.4 million on a retail jurisdictional basis) from the December 31, 2025 forecasted test period prepaid pension asset balance of $229,841,000 ($221,455,000 on a retail jurisdictional basis) that the Company included in rate base. Mr. Gorman's recommendation would reduce the Company's revenue requirement by approximately $2.7 million. Mr. Gorman testified that the Company failed to demonstrate that the forecasted increases in its prepaid pension asset were funded by investor capital and, therefore, it should be removed from cost of service. Mr. Gorman explained that the Commission previously found that ratepayers do not owe a utility a return on a portion of a prepaid pension asset that represents the minimum funding level under the Employee Retirement Income Security Act of 1974. He noted that Duke stated in its response to Industrial Group Data Request 10.16 that "Annual ERISA minimum pension contributions are applicable on a plan basis only, not to Duke specifically, as Duke participates in plans sponsored by Duke Energy Corporation. Therefore, the requested data is unavailable." IG Ex. 1 at 38.

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[9] We note the Industrial Group's separately recommended that rate relief with respect to Duke's TDSIC expenditures should be specified as interim and subject to reconciliation pending the outcome of the Indiana Supreme Court's decision in the appeal of Cause No. 45647 which approved Duke's TDISC 2.0. Subsequent to the evidentiary hearing, the Indiana Supreme Court affirmed the Commission's Order regarding Cause No. 45647 in *Ind. Off. of Util. Consumer Couns. v. Duke Energy Indiana, LLC,* 2024 WL 5165065 (Ind. Dec. 19, 2024). Due to mootness, we therefore do not address the parties' evidence and arguments relating to Industrial Group interim treatment recommendation.

Mr. Gorman explained that because pension expense is a non-cash Generally Accepted Accounting Principles ("GAAP") expense, if a utility recovers through rates more than the GAAP financial pension expense, the excess paid in rates could fund cash contributions to the pension trust. Mr. Gorman testified to the extent that all or part of the prepaid pension asset was funded by either contributions from customers in excess of pension costs, or returns on the pension trust, then the utility is not entitled to charge customers a rate of return on the portion of the asset not funded by shareholders.

iii. <u>Duke Rebuttal</u>. On rebuttal, Company witness Graft testified Mr. Gorman's comparison of cumulative contributions to the amount of pension expense that has been included in the revenue requirement in past cases is inappropriate and has been rejected by the Commission as retroactive ratemaking in the most recent Order from the Commission addressing a prepaid pension asset. Ms. Graft explained that Mr. Gorman is attempting to isolate one component of the revenue requirement as his basis for denying the Company recovery of a fair return. Ms. Graft testified the prepaid pension asset represents the cumulative amount of cash contributions to the pension trust fund in excess of the cumulative amount of actuarially determined GAAP pension costs. She explained only GAAP pension costs are included in the Company's cost of service; accordingly, any amounts contributed to the pension trust in excess of GAAP pension costs have to come from investors and therefore, the prepaid pension asset is fully funded by investors and should earn a return. Ms. Graft further testified the Commission previously approved the full forecasted test period prepaid pension asset amount included in Cause No. 45253, and the Company's inclusion of the proposed test period year-end prepaid pension asset in rate base is this proceeding is reasonable.

iv. <u>Commission Discussion and Findings</u>. The Commission must address two issues in considering the inclusion of a pension asset in rate base. First, the Commission must determine whether pension assets are prepayments that were prudently made for the benefit of customers and were made using investor-supplied funds and therefore would be considered working capital and effectively the same as used and useful utility property under Ind. Code § 8-1-2-6. We have previously found that a prepaid pension asset may be classified as working capital, and thus treated as used and useful utility property, if the prepayments were prudently made for the benefit of customers and were made using investor-supplied funds. *See Indianapolis Power & Light Company*, Cause Nos. 44576 and 44602 (IURC Mar. 16, 2016). If the prepaid pension asset is working capital, then we must then address what amount of the prepaid asset should be recognized as investor capital on which a return should be provided.

In this case, Duke has demonstrated that a prepaid pension asset of $229.841 million ($221.455 on a retail jurisdictional basis) exists, and that prepaid pension asset has been recorded on the Company's books in accordance with applicable accounting standards. The record also reflects that the prepaid pension asset has reduced the pension cost reflected in the revenue requirement in this case, and the asset serves to preserve the integrity of the pension fund. Further, the record demonstrates that Duke made discretionary management decisions to make use of available cash to secure its pension funds and reduce the liquidity risk of future payments, through contributions to its pension fund in excess of actuarially determined GAAP pension costs. It is undisputed that the prepayment benefits ratepayers by reducing total pension costs in the Company's revenue requirement. There is no dispute as to the beginning balance of the pension asset nor that this amount was investor contributed. Nor is there a dispute that this amount was paid for the benefit of customers. Therefore, the beginning amount is working capital treated as used and useful utility property. These facts are similar to the facts surrounding the prepaid pension asset we found should be included in Duke's rate base in Cause No. 45253.

In *Indiana American Water Co.,* Cause No. 45870 (IURC Feb. 14, 2024), Mr. Gorman made a very similar argument to the one he set forth in the current Cause. We stated in our Order in Cause No. 45870 that "Mr. Gorman's reliance on comparisons of past amounts reflected in rates to actual expense to disallow the prepaid pension asset [was] . . . prohibited retroactive ratemaking." *Id.* at 46. For this same reason, we reject Mr. Gorman's adjustment in the current Cause.

Based on the evidence presented, we find Duke's forecasted prepaid pension asset balance is reasonable and is approved.

H. Original Cost of Duke's Rate Base. Based upon the evidence presented in this case, and the findings discussed above, we find that the Step 1 jurisdictional net original cost of Duke's rate base used and useful for the benefit of the public to be $12,005,252,000, comprised of the following elements:

Net Electric Utility Plant in Service	$10,760,260,000
Fuel Inventory	$130,594,000
Regulatory Assets	$529,750,000
Materials and Supplies	$363,193,000
Prepaid Pension Asset	$221,455,000
NET UTILITY RATE BASE	$12,005,252,000

Further, we find that the Step 2 jurisdictional net original cost of Duke's rate base used and useful for the benefit of the public is forecasted to be $12,481,993,000 at December 31, 2025, comprised of the following elements:

Net Electric Utility Plant in Service	$11,237,018,000
Fuel Inventory	$130,594,000
Regulatory Assets	$529,750,000
Materials and Supplies	$363,176,000
Prepaid Pension Asset	$221,455,000
NET UTILITY RATE BASE	$12,481,993,000

I. Fair Value of Duke's Rate Base. Duke proposed that a fair return for purposes of this case be based on its weighted cost of capital times its original cost rate base. No party disputed that net original cost should be used as the fair value of Duke's utility plant in service in this case, or that a fair return for Duke should be based on its weighted cost of capital. Accordingly, we find that, for purposes of this proceeding, Duke's fair value rate base is the same as its original cost rate base ($12,481,993,000), and that this fair value rate base should be used for purposes of Ind. Code § 8-1-2-6.

i. **Fair Rate of Return**.

a. **Capital Structure.**

1. Duke Case-in-Chief. Company witness Bauer presented Duke's current and projected capital structures. Mr. Bauer testified Duke's financial capital structure as of August 31, 2023, was 47.6% long-term debt and 52.4% equity. He further testified Duke's capital structure is forecasted to be 47% long-term debt and 53% equity at the end of 2025 (the end of the Forward-Looking Test Period). He testified this forecasted capital structure is consistent with the Company's target capital structure of 47% long-term debt and 53% equity for Duke as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. He further testified the use of the forecasted capital structure in setting Duke's rates will help Duke maintain its credit quality and this level is also consistent with the Company's target credit metrics needed to support its current credit ratings. Ms. Sieferman testified and supported the Company's regulatory capital structure, incorporating Mr. Bauer's forecasted financial capital structure, as shown in Duke's Exhibit 26, Attachment 26-C, Schedule CS1.

Ms. Sieferman explained that both the historic base period and forecasted Forward-Looking Test Period capital structure and cost of capital had been calculated using the same expanded regulatory presentation and the same methodology as has been used in recent years for the Company's last base rate case in Cause No. 45253, and all of the Company's trackers that include return on investment as part of the calculation and the same basic workpapers are being filed in this case as parties have seen in the various tracker filings. She testified that the forecasted financial capital structure had been expanded to include traditional Indiana regulatory components including accumulated deferred income taxes, unamortized investment tax credits ("ITC"), and customer deposits. Ms. Sieferman further testified the components of the Company's regulatory capital structure included cost rates computed in accordance with traditional Indiana regulatory practice (the embedded cost of long-term debt, average financial rates for ITC and zero cost of capital for accumulated deferred income taxes). She explained the Company is proposing the Commission approve the Company's request to allow it to use a 5% interest rate on customer deposits included for the Forward-Looking Test Period, rather than the 2% currently effective rate, to better reflect the current interest rate environment.

Ms. Sieferman also explained that, as has been standard practice in the calculation of the Company's regulatory capital structure for many years, the Company removed a long-term financing issuance specifically related to the liability assumed by the Company to pay the Rural Utility Service resulting from the settlement of litigation with Wabash Valley as well as removing the Gas Pipeline Lease Liability recorded as a capital lease for payments under a Gas Services Agreement with CenterPoint, to provide gas to the Edwardsport IGCC plant via a gas pipeline which CenterPoint constructed and owns ("Gas Pipeline Lease"). Ms. Sieferman explained this was removed for ratemaking due to the treatment of the payments under the lease for both ratemaking and income tax purposes as a "pay-as-you-go" operating lease rather than a capital lease. In addition, adjustments were made to eliminate certain deferred income taxes recorded on the Company's books for financial statement reporting purposes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, but which have historically been excluded from the capital structure for ratemaking purposes, as well as to remove the deferred income taxes related to the Gas Pipeline Lease. Ms. Sieferman explained that the Company also removed the accumulated deferred income tax balances associated with the non-jurisdictional Rural Utility Service debt, which was removed from the capital structure, as well as with the Company's former manufactured gas plant sites. As approved by the Commission in its Order in Cause No. 43114 IGCC 4S1, the Company excluded deferred income taxes associated with the amount of the IGCC capital investment in excess of the agreed-upon Hard Cost Cap, including additional allowance for funds used during construction from the capitalization structure for purposes of calculating the rate of return. Ms. Sieferman explained an adjustment was made to remove the deferred income tax asset balances related to the Company's deferred utilization of ITCs and to include the unamortized balance of the regulatory liability for the excess deferred income taxes amounts resulting from the 2017 Tax Cuts and Jobs Act ("TCJA") and from other previous state and federal tax changes as an additional zero cost source of capital component in the calculation. Finally, Ms. Sieferman explained that short-term debt has been excluded from the capital structure, consistent with previous Commission orders, including the Company's last base rate case in Cause No. 45253. However, Ms. Sieferman testified the Company has included a $150,000,000 inter-company notes payable for Commercial Paper issued by Duke Energy Corporation on behalf of the Company that is part of the Company's permanent long-term financing.

2. Industrial Group Case-in-Chief. Mr. Gorman testified the Company's projected ratemaking capital structure is reasonably comparable to the capital structure last approved for setting Duke's rates; however, he testified the Company's capital structure is relatively expensive compared to the ratemaking capital structure approved for other utilities. Mr. Gorman compared the Company's projected capital structure to that of the State Authorized Common Equity Ratios from 2013 to 2024 and stated that Duke's proposed ratemaking capital structure is more expensive and its common equity ratio is greater than that of other utilities. He further explained that Duke's proposed ratemaking capital structure implies a level of debt leverage that is lower than the level that Duke can support while maintaining its bond rating. We note Mr. Gorman did not recommend a different capital structure for the Company from the 53% equity and 47% debt structure projected by Mr. Bauer.

3. OUCC Case-in-Chief. OUCC witness D. Garrett testified he was not recommending an imputed capital structure for Duke, but explained that this does not mean no adjustment should be made to account for the discrepancy in financial risk between Duke and a proxy group of utility companies. Mr. Garrett testified that the average debt ratio of the utility proxy group reported in Value Line is 54%, which is notably higher than the Company's proposed debt ratio of only 47%. As such, he recommended that a mathematical adjustment be made to his Capital Asset Pricing Model ("CAPM") results via the Hamada Model to effectively align the Company's capital structure with the proxy group's capital structure.

4. Duke Rebuttal. On rebuttal, Ms. Sieferman presented an update to the Company's Step 1 forecasted capital structure and cost of capital information to reflect actual balances as of June 30, 2024, and included the information in Exhibit 49, Schedules RA18 and RA19. Ms. Sieferman testified while there were no notable differences between the forecasted June 30, 2024 capital structure and cost of capital data and the actual June 30, 2024 amounts being presented on rebuttal, there were some minor differences between the forecasted and actual data. She testified the actual June 30, 2024, capital structure for Step 1 reflects an updated authorized rate of return of 6.39% compared to the estimate of 6.33%. Further, she testified the updated debt/equity ratio is 47.0%/53.0% versus the estimate of 47.3%/52.7%. Ms. Sieferman further testified the weighted average rate for long-term debt increased slightly from 4.86% to 4.89% due to higher than forecasted interest rates on a few debt issuances. Ms. Sieferman testified most other items remained relatively unchanged.

Ms. Sieferman testified this updated information will be used, in conjunction with the actual used and useful net plant in-service as of June 30, 2024, to calculate the Step 1 adjustments. She stated that the actual June 30, 2024 data for used and useful net plant-in-service is discussed in the rebuttal testimonies of Company witnesses Graft and Lilly.

Company witnesses Bauer and McKenzie responded to Mr. Garrett's mathematical adjustment to his CAPM results in order to effectively align the Company's capital structure with the proxy group's capital structure and explained why the comparison was not appropriate. Regarding Mr. Gorman's suggestion that the Company's capital structure is relatively expensive compared to the ratemaking capital structure approved for other utilities, Mr. Bauer testified that excluding the very limited number of rate cases in the first quarter of 2024, there is a clear upward trend in equity ratios since 2020. Further, Mr. Bauer testified that, when comparing the projected capital structure of Duke in this rate case to those of similar vertically integrated rate cases (excluding transmission only, distribution only cases, and limited issue rider cases), it is clear that the Company's 53% equity / 47% debt capital structure is reasonable.

5. Commission Discussion and Findings. No party disputed the Company's projected capital structure or recommended a different capital structure from the 53% equity and 47% debt structure Mr. Bauer projected. OUCC witness Mr. Garrett recommended a downward adjustment to his CAPM analysis for purposes of determining an appropriate ROE based on the Company's projected capital structure, but he did not recommend a different capital structure. This issue is addressed below in our discussion of an appropriate ROE for the Company. Further, Mr. Gorman claimed the Company's capital structure is relatively expensive compared to the ratemaking capital structure approved for other utilities; however, Mr. Bauer's rebuttal testimony demonstrates the Company's projected capital structure in this case is in line with rate cases of similar vertically integrated utilities.

Turning now to the appropriate equity component to use in the capital structure for setting rates for Duke, we find that Duke's forecasted capital structure at each of the relevant cutoff dates for the implementation of rates in two steps are reasonable. Longstanding Indiana precedent requires the use of a utility's actual, not hypothetical, capital structure when setting rates. Hypothetical capital structures are contrary to Indiana law. *See Public Service Comm'n of Ind. v. Ind. Bell Tel. Co.,* 235 Ind. 1, 130, N.E.2d 467 (Ind. 1955). Although we are dealing with a future test period in this case and are using forecasted capital structures at this point in the process, the Company's proposal will incorporate its actual capital structure, not a forecasted capital structure, when implementing its Step 1 and Step 2 rate increases. We find the proposed equity and debt components to be comparable to those of similarly situated utilities and in line with this Commission's prior findings on what constitutes a reasonable capital structure to satisfy legal standards and our charge under Indiana law to ensure that rates are just and reasonable while affording the utility an opportunity to earn a fair return. Accordingly, we accept Duke's proposed capital structure in this case.

b. **Cost of Debt.** Mr. Bauer testified that Duke's current (as of August 31, 2023) weighted average cost of long-term debt is 4.83% and Duke's weighted average cost of long-term debt is forecasted to be 4.87% at the end of 2025 (the end of the Forward-Looking Test Period). On rebuttal, the Company updated the Step 1 forecasted capital structure and cost of capital information to reflect actual balances as of June 30, 2024. This information was included in Exhibit 49, Schedules RA18 and RA19. No party disputed these costs and we approve them.

c. **Return on Equity.**

1. **Duke Case-in-Chief.** Company witness Adrien McKenzie supported Duke's ROE and testified in support of the Company's projected capital structure. Mr. McKenzie recommended an ROE of 10.8% as a just and reasonable ROE. However, as explained by Company witness Pinegar, the Company is proposing an ROE of 10.5% for rate mitigation purposes and to assist in establishing rates that are affordable and competitive across all customer classes.

Mr. McKenzie explained that the standard for determining a just and reasonable ROE was set forth in the U.S. Supreme Court's findings in *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 43 S.Ct. 675 (1923) and *Fed. Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591, 64 S.Ct. 281 (1944). Mr. McKenzie testified the U.S. Supreme Court's findings in *Hope* and *Bluefield* established that a just and reasonable ROE must be sufficient to: (1) fairly compensate the utility's investors, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity. Mr. McKenzie testified these standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the U.S. Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

In determining his recommended ROE, Mr. McKenzie first developed a proxy group of utility companies that face similar risk as Duke. To that proxy group, he applied the discounted cash flow ("DCF") model, the CAPM, the empirical CAPM ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for electric utilities, which he testified are all methods that are commonly relied on in regulatory proceedings. Mr. McKenzie further testified his evaluation takes into account the specific risks for the Company's electric operations in Indiana and Duke's requirements for financial strength. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, Mr. McKenzie corroborated his utility quantitative analyses by applying the DCF model to a group of low-risk non-utility firms.

Mr. McKenzie presented the results of his DCF, CAPM, ECAPM, risk premium, and expected earnings analyses, ultimately recommending an ROE range for the Company's electric operations of 10.3% to 11.3%. He concluded that the 10.8% midpoint of this range represents a just and reasonable ROE that is adequate to compensate the Company's investors, while maintaining the Company's financial integrity and ability to attract capital on reasonable terms.

Mr. McKenzie testified that fundamental financial principles and capital market trends justify a significant increase to Duke's authorized ROE. He explained that because investors evaluate investments against available alternatives, the ROE and the cost of long-term debt are inextricably linked. Mr. McKenzie's testimony demonstrated that long-term bond yields climbed dramatically beginning in 2022 and investors anticipate that these increases will be sustained. Mr. McKenzie testified that the upward move in interest rates suggests that long-term capital costs—including the ROE—have increased significantly since the Commission determined that the unadjusted cost of capital for Duke was 9.75%. Mr. McKenzie further demonstrated in his testimony how other market conditions such as the exposure to rising interest rates, inflation, and capital expenditure requirements reinforced the importance of buttressing Duke's credit standing. Mr. McKenzie explained that when considering the potential for financial market instability, competition with other investment alternatives, and investors' sensitivity to risk exposures in the utility industry, credit strength is a key ingredient in maintaining access to capital at reasonable cost.

He testified it would be unreasonable to disregard the implications of these current capital market conditions in establishing a fair ROE for Duke. He explained that if the upward shift in investors' risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. He testified that failing to provide investors with the opportunity to earn a rate of return commensurate with Duke's risks will weaken its financial integrity, while hampering the Company's ability to attract necessary capital.

Mr. McKenzie described his process of selecting a group of proxy companies to estimate the ROE for Duke. He then walked through his use of the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses for estimated ROE. His application of the constant growth DCF model resulted in ROE estimates in the range of 9.1% to 10.6%. His traditional CAPM analyses implied an average ROE of 11.5% after adjusting for the impact of firm size, and his ECAPM analysis resulted in an average ROE estimate of 11.7%, after incorporating the size adjustment corresponding to the market capitalization and of the individual utilities. His risk premium method analysis implied a current ROE of 10.79%, and his expected earnings method analysis suggested an average ROE of 11.3%. Mr. McKenzie also performed a DCF analysis for a group of low-risk firms in the competitive sector, which resulted in ROE estimates in the range of 10.5% to 11.0%.

2. <u>CAC Case-in-Chief</u>. Mr. Inskeep recommended the Commission approve an ROE at the lower end of the range the Commission determines reasonable, and recommended the Commission further reduce the Company's ROE to incent the Company to approach future cases in a more cooperative and transparent spirit. Mr. Inskeep recommended a downward adjustment of 20 basis points from the ROE that the Commission finds should be authorized.

3. **Industrial Group Case-in-Chief.** Industrial Group witness Mr. Gorman recommended that the Commission award an ROE between 9.30% and 9.65%, with an approximate midpoint of 9.50%. Mr. Gorman supported his recommended ROE with DCF, risk premium, and CAPM analyses. Mr. Gorman explained that in conducting these analyses, he relied on the same utility proxy group developed by Duke witness McKenzie. Mr. Gorman noted that based on Duke's credit rating and proposed common equity ratio compared to the proxy group averages, Duke has lower financial risk relative to the proxy group. Therefore, Mr. Gorman explained, that the proxy group will produce a conservative ROE for Duke.

Mr. Gorman testified that his recommended ROE would result in a $71.6 million reduction to Duke's claimed revenue deficiency. Mr. Gorman explained that this return would fairly compensate Duke for its current market cost of common equity while also preserving its credit rating, its access to capital on reasonable terms, and financial integrity. Mr. Gorman explained that Duke's proposed ROE of 10.5% is significantly higher than the current ROE for low-risk regulated utilities like Duke and that setting rates based on an above-market ROE would result in rates being set above a just and reasonable level and thus, would harm customers.

Mr. Gorman explained that observable data, including data on industry authorized returns on equity, trends and outlooks on credit standing, and the ability of utilities to attract capital to fund large investments, provides clear evidence that industry authorized returns on equity have been judged by market participants to be fair and reasonable. Thus, Mr. Gorman testified that in relation to Duke's ROE in this case, it is significant to observe that average industry authorized returns on equity for regulated utilities have ranged from 9.39% to 9.78% for the period from 2014 through 2023 and, that between 2020 and 2023, authorized returns on equity have averaged around 9.50%.

Mr. Gorman also testified that utility valuation metrics continue to demonstrate that utilities can sell new stock at robust market prices, which illustrates that utilities can access equity capital under reasonable terms and conditions, and at relatively low cost. He provided a detailed analysis of utility markets and concluded that even as authorized ROEs have fallen into the mid-9% range, utilities continue to have access to large amounts of external capital while still funding large capital programs and utilities' investment-grade credit ratings remain stable.

Mr. Gorman contested several issues with the various analyses Mr. McKenzie performed in the development of his ROE recommendation. Regarding Mr. McKenzie's DCF analysis, Mr. Gorman explained that Mr. McKenzie's decision to selectively exclude what he believes to be low or high outliers from the proxy group, as opposed to relying on the median DCF return results, has the effect of manipulating the results of the proxy groups. Mr. Gorman also stated that Mr. McKenzie's DCF results are based on growth rate estimates that substantially exceed the maximum long-term growth of the U.S. economy as measured by the gross domestic product and cannot be sustained in the long run. Mr. Gorman further testified that he disagrees with Mr. McKenzie's view that his non-utility DCF is relevant in evaluating a fair ROE for Duke, although Mr. Gorman also acknowledged that Mr. McKenzie did not rely on the results of the non-utility DCF model. In regard to Mr. McKenzie's traditional CAPM and ECAPM analyses, Mr. Gorman testified that he disagreed with the derivation of Mr. McKenzie's market risk premium because it is based on a growth rate that is more than twice the growth rate of the U.S. gross domestic product long-term growth outlook and thus, does not reflect a reasonable estimate of the expected return on the market. Mr. Gorman stated that as a result of Mr. McKenzie's long-term market growth rate estimate, the market DCF return used in his CAPM analyses is inflated and not reliable. Mr. Gorman also testified that Mr. McKenzie's CAPM and ECAPM analyses are based on a size adjustment that is not based on risk comparable companies relative to the utility industry or Duke, which artificially inflates the fair and reasonable return for Duke. Regarding Mr. McKenzie's utility equity risk premium analysis, Mr. Gorman testified that Mr. McKenzie's analysis incorrectly contended that there is a simplistic inverse relationship between equity risk premiums and interest rates without any regard to differences in investment risks and does not produce accurate risk premium estimates. Mr. Gorman explained that while interest rates are a relevant factor in assessing current market equity risk premiums, the risk premium ties more specifically to the market's perception of investment risk of debt and equity securities, and not simply changes in interest rates. Regarding Mr. McKenzie's expected earnings analysis, Mr. Gorman testified that this form of analysis does not measure the return an investor requires in order to make an investment and is not a reasonable method for estimating a fair ROE.

4. <u>OUCC Case-in-Chief</u>. OUCC witness D. Garrett recommended an ROE of 9.0% for Duke. He arrived at his recommendation by considering the results of the DCF model and the CAPM model, which produce a range of 7.9% to 9.5%. Mr. Garrett described his DCF model analysis and the inputs he used for his model. Mr. Garrett testified he considered two variations: one using analysts' growth rates and one using a sustainable growth rate, and the results of these models were 9.2% and 7.9%, respectively. Regarding Mr. McKenzie's DCF model, Mr. Garrett testified Mr. McKenzie's DCF results are unreasonably high because he relied on long-term growth rates that are not sustainable. Mr. Garrett testified Mr. McKenzie also eliminated several growth rates from his analysis that he deemed to be too low. Mr. Garrett further testified he does not believe the DCF analysis Mr. McKenzie conducted on the proxy group of non-utility companies indicates an accurate ROE estimate for Duke. As such, Mr. D. Garrett stated the results obtained from Mr. McKenzie's model will be inferior to the results obtained from any model (conducted properly) on the utility proxy group.

Mr. Garrett also described his CAPM analysis and the inputs he used for his model. Mr. Garrett testified the CAPM result is 9.5%, however, all else is not equal, and the CAPM results as applied to Duke should be adjusted to account for the differences between Duke's low-risk capital structure relative to the proxy group. Regarding Mr. McKenzie's CAPM analysis, Mr. Garrett testified Mr. McKenzie's CAPM-derived return on equity is overstated due to his overestimation of the equity risk premium in addition to the unnecessary size adjustment. Mr. Garrett testified Mr. McKenzie also conducts another unnecessary risk premium model in addition to the CAPM. He further testified Mr. McKenzie then also added a premium to his results to account for flotation costs, which affects his overall ROE results.

Mr. Garrett also discussed the Company's capital structure. While Mr. Garrett did not recommend any adjustment to Duke's projected capital structure, he proposed an adjustment to his CAPM results for the Company for purposes of aligning Duke's capital structure to the proxy group's capital structure. Mr. Garrett used the Hamada Model to evaluate the effect of his capital structure recommendation on the Company's ROE, and, based on the model, indicated an ROE estimate (under the CAPM) of 8.9%.

Mr. Eckert also addressed affordability and the impact of regulatory mechanisms on Duke's risks.

5. <u>Walmart Case-in-Chief</u>. Ms. Perry testified the Commission should thoroughly and carefully consider the impact on customers associated with the ROE requested by the Company and should closely examine the Company's proposed ROE in light of the customer impact, the use of a future test year, the Company's currently approved ROE, and recent ROEs approved in Indiana and other jurisdictions. To that end, Ms. Perry provided evidence that that the Company's requested ROE increase from the current authorized ROE of 9.7% to 10.5% would result in an impact on customers of approximately $53.7 million, or 10.90% of the Company's requested rate increase. Furthermore, Ms. Perry demonstrated that the Company's proposed ROE is significantly higher than ROEs approved by the Commission since 2021, noting that the average of Commission-approved ROEs in that period is 9.75%. In comparison to ROEs approved by other regulatory commissions, Ms. Perry presented evidence showing that the average and median of 118 electric utility rate case ROEs approved by regulatory commissions since 2021, as reported by S&P Global Market Intelligence, was 9.50%, with a range of reported ROEs from that period of 7.36% to 11.45%. Ms. Perry further explained that for vertically-integrated utilities reported by S&P Global Market Intelligence over the same time period, the average reported ROE was 9.54% in 2021, 9.60% in 2022, 9.71% in 2023, and 9.72% in 2024 at the time of Ms. Perry's submission of evidence in this case. Ms. Perry concluded that the Company's requested ROE and ROE range are therefore contrary to broader electric industry trends.

6. <u>Duke Rebuttal</u>. On rebuttal, Mr. McKenzie testified the opposing parties' recommendation of a reduction in the Company's ROE is illogical because the Company's capital costs have increased since its last rate proceeding. Mr. McKenzie explained that consideration of current interest rates and the allowed ROE for other electric utilities demonstrate that the ROE recommendations of the opposing parties are far too low. Mr. McKenzie testified that significantly higher bond yields support the view that the ROE is higher now than in 2020 when Duke's current ROE of 9.70% was established. He further testified that adjusting national average allowed ROEs for 2019 through the second quarter of 2024 to account for the recent rise in bond yields implies a current ROE of 10.40%. He further testified adjusting prior ROE determinations of the Commission for current bond yields implies a ROE of 10.46%. Finally, he stated adjusting Duke's currently authorized ROE to recognize that interest rates are now higher implies a current ROE of 10.97%.

Further, Mr. McKenzie testified there are numerous flaws which undermine opposing parties' ROE analyses, including: (1) their reliance on a range of data that fails to reflect in investors' expectations and current capital market conditions; (2) the application of financial models in a manner that is inconsistent with their underlying assumptions; (3) a failure to evaluate model inputs and exclude illogical results; (4) applications of the CAPM that fail to capture a realistic appraisal of investors' forward-looking expectations and ignore the implications of firm size, which biases the resulting ROE estimates downward; and (5) there is no basis to assume that investors reference long-term forecasts of gross domestic product in developing their expectations for utilities and the opposing parties' reference to this data should be rejected. Further, Mr. McKenzie testified there is no basis for Mr. Inskeep's and Mr. Eckert's suggestion that regulatory mechanisms approved for Duke differentiate the Company's risks from the proxy utilities. Mr. McKenzie also testified the ROE penalty proposed by Mr. Inskeep is unsupported and would undermine investors' confidence in the regulatory environment in Indiana. Further, Mr. McKenzie testified the criticisms of his size adjustment, market return calculation, ECAPM, risk premium method, expected earnings approach, and non-utility DCF analysis are without merit.

Mr. McKenzie testified that, taken as a whole, these shortcomings ensure the opposing parties' recommended ROEs fall well below a fair and reasonable level for Duke. He 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. He testified that if the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, he testified that as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. Mr. McKenzie testified that while the Company would undoubtedly continue to meet its service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Indiana, and at what cost.

Additionally, Company witness Bauer testified regarding why Mr. Garrett's adjustment to his CAPM model to account for the difference between the Company's capital structure and that of his proxy group was not appropriate.

7. <u>Commission Discussion and Findings</u>. In setting the rate of return, the Commission's decision must be framed by *Bluefield* and *Hope*. The general standards these cases established require a cost of common equity set by the Commission 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 that could be earned in investments in other enterprises 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., Inc.*, 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 in all 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 and other methods can produce reasonable estimates of a utility's cost of common equity. Consistent with the standards in *Hope* and *Bluefield*, as well as under Indiana law, Duke's authorized ROE should be reasonable given the totality of the circumstances.

The parties proposed various returns using the DCF model and other methods as the basis for their positions, which range from 9.0% to 10.8%. Mr. Pinegar testified that Duke specifically recommended a 10.5% ROE for rate mitigation purposes and to assist in establishing rates that are affordable and competitive across all customer classes.

In addition to the recommendations of these experts, and while not determinative of the ROE in this case, we note the ROE authorized for other Indiana vertically-integrated electric utilities are as noted in the following table:

Utility	Cause No.	Order Date	Authorized ROE
Indiana Michigan Power Company	45933	May 8, 2024	9.85%
Indianapolis Power & Light Company	45911	April 17, 2024	9.90%
Northern Indiana Public Service Company	45772	Aug. 2, 2023	9.80%
Duke	45253	June 29, 2020	9.70%
Southern Indiana Gas and Electric Company[10]	43839	April 27, 2011	10.4%

We are not persuaded Mr. McKenzie appropriately considered the risk mitigation associated with various regulatory mechanisms and ratemaking components, including Duke's use of a future test year in this proceeding; the riders and/or trackers approved for Duke; and the current recovery of future costs (prepayments), resulting from including such costs (like CCR costs and post-closure maintenance costs), upon which Duke requests additional contingency and escalation, in net salvage for purposes of the depreciation rates. His recommendations are also inconsistent with recent ROE decisions approved nationwide for investor-owned electric utilities, as presented by Walmart witness Perry's testimony, and inconsistent with recent Commission orders. While the Commission does not base its ROE conclusion on national averages, the evidence presented demonstrates the trend in approved ROEs for vertically-integrated utilities, both in Indiana and nationwide, is lower than Duke's requested ROE. We recognize financial strength is important for a utility to attract capital at a reasonable cost in order to make the investment necessary to fulfill its service obligations, but the evidence demonstrates investor-owned utilities similar to Duke and located in similar regulatory jurisdictions have been awarded reasonable and fair ROEs that are below Duke's requested range.

Our determination appropriately considers Petitioner's specific risk characteristics, such as the mitigation of risk associated with Petitioner's use of regulatory mechanisms, including a forecasted test year in this proceeding and the multiple trackers approved for Duke, and the future costs the Company will receive through depreciation rates. The effect of these tracking mechanisms is to reduce the uncertainty of the earnings that an investor can expect.

The Commission has considered the analytical results based on a proxy group of electric utilities, as well as the risk factors associated with Duke's generation portfolio and environmental regulations and its planned capital expenditures, among other factors. We find these risk factors are, however, lessened by the future test year Duke used; the trackers Duke is requesting and/or has in place; and the prepayment of future closure costs and environmental compliance costs included with the closure costs, upon which Duke has requested escalation and contingency. All of these factors serve to reduce risks of uncertainty Duke would otherwise face. As we have previously stated:

[10] We note Southern Indiana Gas and Electric Company has a pending base rate case under Cause No. 45990.

Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the rise of volatile earnings results. The general effect of these trackers reduces the uncertainty of earnings that an investor can expect.

Indianapolis Power & Light Co., Cause No. 44576 at 42 (IURC March 16, 2016)

Having taken into consideration the foregoing factors and observable market data reflected in the record, including current and expected long-term capital market conditions, an assessment of the current risk premium built into current market securities, expected inflation rates, and a general assessment of the current investment risk characteristics of the electric utility industry, combined with a thorough understanding of the Indiana jurisdiction and its risk mitigation ratemaking mechanisms, and Duke in particular, the Commission finds a 9.75% ROE is fair and reasonable.

We reach this decision in part by balancing the Five Pillars. We are mindful that while this 9.75% ROE is less than what Duke requested, it is nonetheless an increase in the utility's ROE which will negatively impact affordability. However, we are also mindful that a lower ROE, which would aid affordability, could impact Duke's financial ability to undertake necessary infrastructure investments to support the reliability, stability, resilience, and environmental sustainability pillars. We find that a 9.75% ROE strikes a proper balance between these competing interests.

d. Overall Weighted Average Cost of Capital ("WACC"). Duke's actual capital structure and WACC as of June 30, 2024 and Duke's projected capital structure and WACC as of December 31, 2025 were included in Duke's Exhibit 49 and its supporting schedules. The overall WACC was calculated by summing the component costs of the capital structure, with each component weighted by its respective proportion to total capitalization. Based on the projected capital component balances and component costs described in Mr. Bauer's direct testimony, and as updated for June 30, 2024 actuals, we find Duke's actual WACC as of June 30, 2024 is 6.08 % and its projected WACC is 6.19% as of December 31, 2025, computed as follows:

December 31, 2024				
Description	**Capitalization**	**Ratio**	**Cost**	**Weighted Cost**
Common Equity	$5,398,604,000	42.33%	9.75%	4.13%
Long Term Debt	$4,777,327,000	37.46%	4.89%	1.83%
Deferred Income Taxes	$2,358,702,000	18.49%	0.00%	0.00%
Unamortized ITC – Crane Solar	$11,231,000	0.09%	7.87%	0.01%
Unamortized ITC – 1971 & Later	$378,000	0.00%	7.87%	0.00%
Unamortized ITC – Markland Hydro	$36,011,000	0.28%	7.87%	0.02%
Unamortized ITC – Camp Atterbury Solar	$476,000	0.00%	7.87%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	$133,500,000	1.05%	7.87%	0.08%

Unamortized ITC – Purdue CHP	$4,386,000	0.03%	7.87%	0.00%
Customer Deposits	$34,229,000	0.27%	5.00%	0.01%
Total	$12,754,844,000	100.00%		6.08%

December 31, 2025				
Description	**Capitalization**	**Ratio**	**Cost**	**Weighted Cost**
Common Equity	$5,959,031,000	43.28%	9.75%	4.21%
Long Term Debt	5,278,772,000	38.34%	4.87%	1.87%
Deferred Income Taxes	2,325,599,000	16.89%	0.00%	0.00%
Unamortized ITC – Crane Solar	11,231,000	0.08%	7.86%	0.01%
Unamortized ITC – 1971 & Later	94,000	0.00%	7.86%	0.00%
Unamortized ITC – Markland Hydro	35,947,000	0.26%	7.86%	0.02%
Unamortized ITC – Camp Atterbury Solar	476,000	0.01%	7.86%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	116,978,000	0.85%	7.86%	0.07%
Unamortized ITC – Purdue CHP	4,055,000	0.03%	7.86%	0.00%
Customer Deposits	35,929,000	0.26%	5.00%	0.01%
Total	$ 13,768,112,000	100.00%		6.19%

J. <u>Coal Combustion Residuals Costs</u>.

i. <u>Duke Case-in-Chief</u>. Company witness Riley explained that CCR, or coal ash, is the waste from coal-fired power plants. He stated that coal ash has always been a known cost associated with removing coal generation facilities, but that the extent of these costs has dramatically changed in recent years. Mr. Riley explained that in Cause No. 42359 (Duke's rate case which Duke initiated on December 30, 2002 and in which the Commission issued its Order on May 18, 2004), Duke included a small estimate for the costs associated with remediating coal ash in depreciation rates in effect from May 2004 through July 2020. Mr. Hill described U.S. Environmental Protection Agency ("EPA") rule changes that went into effect in 2015 regarding the safe disposal of CCR. Mr. Riley stated that these changes "significantly increased the cost of remediate coal ash." Pet. Ex. 13 at 32.

He stated that in Cause No. 45253 (Duke's rate case which Duke initiated on July 2, 2019, and in which the Commission issued its Order on June 29, 2020), Duke sought to recover $257 million for actually incurred CCR remediation costs from 2015 to 2018 and $2.399 million of CCR costs estimated to be incurred after the date of the Order. He explained the Commission approved these requests, but that the Indiana Supreme Court reversed the Commission's authorization regarding the $257 million in past costs. He indicated Duke subsequently wrote-off this $257 million. He noted the Indiana Supreme Court decision did not impact the post-Order costs.

Mr. Riley stated that in Cause No. 45253 S1, the Commission granted Duke a CPCN authorizing a return on and recovery of, under the Federal Mandate Statute, approximately $92 million in CCR costs incurred and deferred between January 1, 2019, and November 3, 2021. He stated that the Indiana Court of Appeals subsequently reversed the Commission regarding these pre-Order costs.

Mr. Riley also noted that in Cause No. 45940, Duke sought $327 million in CCR costs. The Commission granted this request in *Duke, LLC*, Cause No. 45940 (IURC May 8, 2024), which is pending appeal under Cause No. 24A-EX-01348.

Mr. Riley testified regarding the CCR costs the Company requests permission to recover in the current Cause. Mr. Riley testified Duke has included estimated future coal ash-related costs in the Company's 2023 decommissioning study. He testified those costs, $131.4 million, include closure costs for future closures of the Company's CCR Units not previously included in Cause Nos. 45253 S1 and 45940. Mr. Riley explained the Company is also requesting the Commission reflect in the calculation of depreciation rates the $92.1 million in costs incurred between January 1, 2019, and November 3, 2021, which were authorized by the CPCN under the Federal Mandate Statute that was later reversed by an Indiana Court of Appeals decision. Mr. Riley explained that these costs should be recorded as costs of removal pursuant to the FERC Uniform System of Accounts.

Company witness Hill testified regarding the future CCR costs (which he detailed in Table 9 on page 9 of Pet. Ex. 19) and stated that the costs were prudent and reasonable. Further, Company witness Spanos explained how the CCR costs have been reflected in the calculation of his recommended depreciation accrual rates.

Mr. Pinegar described why coal combustion residuals are a significant issue in this case and asserted that if environmental sustainability is to be the pillar that the General Assembly has directed, then recovery of prudently incurred costs to sustain the environment must be provided. Mr. Pinegar testified the Company is seeking a path forward to assure recovery of future closure costs.

ii. CAC Case-in-Chief. CAC witness Inskeep recommended the Commission deny cost recovery for all costs incurred by the Company that were previously disallowed by the Indiana Court of Appeals. Mr. Inskeep testified that Duke was not permitted by statute to seek an alternate route for recovering these costs because the Court of Appeals' decision left the Commission's CPCN in place, even as it disallowed recovery of this category of costs, and the mandatory language in the Federal Mandate Statute that costs subject to the CPCN "shall" be subject to that statute prevent Duke from seeking an alternate means of recovery. According to Mr. Inskeep, even if Duke would otherwise have been free to seek recovery of these costs through depreciation, under the circumstances Duke could not seek a hybrid approach to recovering these costs after the Court of Appeals allowed the recovery of some costs but not others pursuant to the CPCN. Mr. Inskeep asserted that, while House Enrolled Act 1417 (2023) expanded the scope of costs that could be sought through depreciation, it did not include language applying its provisions retroactively to costs such as the $92.1 million in historical costs at issue here. He argued that the Commission should reject the Company's proposed cost recovery.

CAC witness Inskeep contended that Duke has substantial, additional CCR costs that have not yet been identified and brought to the Commission for approval—potentially hundreds of millions of dollars or more of such costs. These costs include potential corrective actions to address contaminated groundwater, as well as potential additional future closure costs due to the a May 18, 2023 EPA rule ("Legacy CCR Rule"). Mr. Inskeep asserted Duke is seeking to recover the costs of both past and future closure projects that may not be sufficient to prevent or minimize the need for additional costs in the future, a topic he said is discussed extensively by CAC witness Frank. Dr. Frank also testified that Duke has failed to comply with an EPA determination that Duke's Gallagher site (and by implication, others similarly situated) must comply with federal regulations where inactive disposal units were in contact with groundwater. According to Dr. Frank, these additional federal compliance obligations are likely at Ash Disposal Area #1 and West Ash Fill Area at Cayuga; North Ash Pond, Primary Pond Ash Fill, Coal Pile Ash Fill at Gallagher; South Ash Fill Area, and "North Ash Pond Not Regulated by the CCR Rule" at Gibson; and North Ash Pond at Wabash River. Dr. Frank further testified that Duke's closure of coal ash disposal units in contact with groundwater and/or in the floodplain also violates federal and state coal ash regulations.

Both Dr. Frank and Mr. Inskeep testified that the high CCR closure and cleanup costs (both past and future) that Duke is facing now are the result of the Company failing to prudently and safely manage and dispose of vast quantities of CCR over many decades. Dr. Frank further asserted that Duke's decisions over decades to dispose of CCR in unlined disposal units, floodplains, and/or in contact with groundwater have led to widespread groundwater contamination from CCR at Duke's sites, which plays a significant role in increasing the costs that Duke is now seeking to pass on to ratepayers. In addition, Dr. Frank described how Vectren (now CenterPoint) in Indiana, as well as Duke affiliates in North and South Carolina and utilities in other states including Tennessee and Virginia, have concluded that closure of CCR units by removal is more cost-effective in the long term than closure-in-place.

Dr. Frank recommended that the Commission require Duke to perform a comprehensive evaluation of current and future coal ash costs at each of its sites. Dr. Frank also recommended that the Commission make clear that Duke shareholders bear the risk of less protective CCR cleanups and closures, and that the Commission deny Duke's requests to recover costs for cleanup and disposal of coal ash in an unsafe and imprudent manner and/or in a manner that does not comply with federal and state regulations.

Mr. Inskeep similarly recommended that the Commission reject cost recovery of CCR projects to the extent that the Commission determines that all or a portion of the project costs are necessary because of Duke's unsafe or imprudent disposal of CCR, or otherwise determines that they are not just or reasonable.

iii. <u>Industrial Group Case-in-Chief</u>. Mr. Andrews opposed Duke's $92.1 million cost recovery request because he contended the Company is attempting to recover coal ash asset retirement obligation ("ARO") costs that have already been incurred. Mr. Andrews testified he is not aware of Duke having authority to recover the costs incurred prior to 2022, as the Indiana Court of Appeals reversed the Commission's decision approving these costs. Further, Mr. Andrews testified Duke has both inappropriately escalated these costs and has double-counted them in their calculations. Mr. Andrews explained that Mr. Spanos has an error in the workpaper that supports Table 3 of the depreciation study, which includes the Coal Ash ARO costs twice in the terminal net salvage rate calculations. Mr. Andrews testified that for this $92.1 million of incurred costs, Duke is actually attempting to recover $245 million through depreciation rates. Mr.

Andrews recommended the costs, specifically $245.15 million, be removed from the terminal net salvage rate calculations.

iv. <u>OUCC Case-in-Chief</u>. OUCC witness Armstrong recommended the Commission deny Duke's request to recover CCR closure costs that were incurred prior to the Commission's Order in Cause No. 45253 S1 because recovery of these costs was resolved in the appeal of the 45253 S1 Order. Ms. Armstrong testified the OUCC opposes Duke's proposal to again recover $92,075,402 in past CCR closure costs that were at issue in Cause No. 45253 S1 through traditional cost of removal accounting in base rates. She explained that while the Commission originally approved recovery of these costs as part of the overall Coal Ash Compliance Plan that Duke presented, the Indiana Court of Appeals reversed that Order, finding these costs were ineligible for recovery under the applicable Federal Mandate Statute in effect at that time. She noted that following the Court's reversal and remand to the Commission, Duke calculated the refunds Duke owed its ratepayers and agreed to begin refunding these dollars in Cause No. 42061 ECR 39. She stated the refund of these costs has been substantially completed through subsequent environmental cost recovery ("ECR") proceedings.

Ms. Armstrong maintained that collecting these dollars from ratepayers a second time is unfair and unprecedented.

Ms. Armstrong also noted that Duke confirmed it inadvertently escalated the $92.1 million when these costs were included in its depreciation study, increasing the total amount included in the study to $122,575,419. She testified that Duke stated this amount would be corrected in its rebuttal testimony, but this correction will not alter the impropriety of Duke now seeking the same dollars again from its ratepayers.

Ms. Armstong testified the OUCC does not take issue with Duke's proposal to recover future CCR closure costs through decommissioning and that traditional depreciation accounting is the standard way future decommissioning costs are recovered and allows Duke to collect the amount reasonably necessary to close these sites and fund an appropriate depreciation reserve. She stated traditional depreciation accounting also reduces intergenerational equity issues and better aligns costs with customers who received the benefits associated with these assets. Consistent with OUCC witness D. Garrett's recommendations, Ms. Armstrong opposed the inclusion of contingency costs in decommissioning estimates. She also noted that since Duke does not expect to incur these costs until the 2031–2045 time frame, these costs could be addressed in a future rate case.

OUCC witness D. Garrett testified there was an error in the Company's depreciation study regarding the calculation of production net salvage rates related to the escalation factors, and therefore the approximately $92.1 million of coal ash ARO costs were escalated and double counted.

v. <u>Duke Rebuttal</u>. On rebuttal, Mr. Riley explained why Duke believes it is appropriate for the Company to recover the $92.1 million CCR costs incurred from January 2019 through November 2021 in this proceeding. Mr. Riley explained that in its decision in Cause No. 45253 S1, the Indiana Court of Appeals concluded that CCR-related costs incurred prior to Commission approval of the Company's CPCN should not be recovered under the Federal Mandate Statute (Indiana Code ch. 8-1-8.4). Mr. Riley testified it should be noted that the Indiana Court of Appeals left the Company's CPCN intact, indicating their approval of the concept of recovery of CCR-related costs under the Federal Mandate Statute. Mr. Riley explained that no party alleged that these CCR costs are imprudent, however, witnesses Armstrong, Inskeep, and Andrews do not accept that there are other acceptable approaches for capital costs, such as the CCR costs, to be recovered in the ratemaking process, creating an inequitable gap in recovery. Mr. Riley explained there are numerous methods for recovery of these costs, including a traditional cost of removal methodology, as well as under the Federal Mandate Statute. While the Court of Appeals determined the Federal Mandate Statute was not the appropriate recovery method for the $92.1 million in pre-Order costs, the Court did not address the reasonableness and prudence of these costs, nor did it foreclose the recovery through any other methods.

Ms. Lilly noted that the entry to debit Accumulated Depreciation has not yet been made, because that entry would not be made until issuance of an Order in this proceeding approving the inclusion of those costs in depreciation. As such, the entry would not be reflected in Step 1 net original cost rate base. It would, however, be reflected in the Step 2 compliance filing.

Mr. Hill testified in rebuttal that Duke's closure plans are reasonable because they were proposed by Company engineers and approved by IDEM and, he claimed, neither would support a closure plan that did not comply or posed unnecessary risk. Mr. Hill also acknowledged that Duke continues to assess the closure plans at each of its sites, which he indicated would ensure compliance with the federal Legacy CCR Rule.

vi. Additional Evidence Received at Hearing. During cross-examination at the hearing, Duke witness Pinegar acknowledged that the Company could have sought pre-approval ratemaking for CCR costs prior to 2019 but did not do so. Both Mr. Pinegar and Duke witness Hill also acknowledged that EPA found that the Gallagher site's closure plans were out of compliance with federal CCR regulations, even though IDEM had already approved the plans. In response to U.S. EPA's determination that the Gallagher closure plans were out of compliance with federal CCR regulations, Duke withdrew and resubmitted the Gallagher closure plans, adding engineering controls including a slurry wall and a dewatering system that increased the cost of the plans. Mr. Pinegar acknowledged that Duke had not re-evaluated any of its other sites where there was a potential for CCR to be in contact with groundwater to assess whether those sites' closure plans were out of compliance with federal CCR regulations, in light of U.S. EPA's regulatory determination. Mr. Hill further testified that Duke does not agree with U.S. EPA's regulatory determination, which was upheld by the U.S. Court of Appeals for the District of Columbia Circuit. Specifically, the federal appeals court found that the EPA letter regarding the Gallagher site, along with several other similar determinations, "simply explains, interprets, and applies" federal CCR regulations to those sites, CAC Ex. CX-11, in finding that Gallagher and other sites were subject to the 2015 federal CCR regulations. Mr. Hill also testified that regardless of whether Duke's CCR closure plans complied with federal regulations at the time they were completed, the Company would be conducting a new assessment of its CCR disposal sites to determine whether additional steps would be needed to comply with the Legacy CCR Rule, including considering whether additional engineering controls would be needed at all its Indiana sites. Mr. Pinegar declined to commit Duke to collaborating with stakeholders to study the long-term costs of addressing groundwater contamination and ensuring safe closure at their sites.

vii. Commission Discussion and Findings. Based upon the Indiana Supreme Court's decision regarding Cause No. 45253, *Ind. Off. of Util. Consumer Couns. v. Duke Energy Ind., LLC*, 183 N.E.3d 266 (Ind. 2022) ("*OUCC v. Duke I*"), we deny Duke's request to recover its January 1, 2019 to November 3, 2021 CCR costs. We grant Duke's request to recover its designated future CCR costs.

a. January 1, 2019 to November 3, 2021 CCR Costs. Pursuant to Ind. Code §§ 8-1-2-19 through 21, Duke seeks to recover CCR costs incurred and deferred into a regulatory asset between January 1, 2019 and November 3, 2021. The parties agree that these costs are the same as those costs which Duke sought and the Commission granted authority to recover, based upon the federal mandate statute through Cause No. 45253 S1. In *Ind. Off. of Util. Consumer Couns. v. Duke Energy Ind.*, LLC, 204 N.E.3d 947 (Ind. Ct. App. 2023), the Indiana Court of Appeals reversed the Commission's determination. We note the OUCC and other parties argued that Duke's request to recover these CCR costs is barred by res judicata in light of the reversal by the Court of Appeals. We do not address the res judicata arguments because we find the Indiana Supreme Court's decision in *OUCC v. Duke I* to be dispositive.

We disagree with Duke's argument that its recovery of the January 1, 2019 and November 3, 2021 CCR costs is mandatory pursuant to the language of Ind. Code §§ 8-1-2-19 through -21. In *OUCC v. Duke I*, the Court considered "whether a utility can recover past costs, adjudicated under a prior rate order, by treating the costs as a capitalized asset." *OUCC v. Duke I* at 267. In 2004, the Commission issued an Order in Duke's prior base rate case (Cause No. 42359) in which the Commission "adjudicated depreciation rates for the cost of decommissioning its plant assets, including coal-ash costs." *Id*. at 270. In Duke's next rate case (Cause No. 45253), Duke in part sought recovery of CCR costs through 2018 which had increased more than Duke had anticipated in Cause No. 42359. The Commission granted this recovery, which the Indiana Supreme Court reversed, finding that the Commission's Order violated the prohibition against retroactive ratemaking. To reach this decision, the Indiana Supreme Court relied, in part, upon Ind. Code § 8-1-2-68 which provides that "Whenever ... the commission shall find any rates ... to be unjust, unreasonable, [or] insufficient …, the commission shall determine and by order fix just and reasonable rates ... to be imposed, observed, and *followed in the future***.**" *Id*. at 268 (emphasis added by the Court). The Court also noted that "[p]ast losses of a utility cannot be recovered from consumers nor can consumers claim a return of profits and earnings which may appear excessive" (*Public Service Commission of Indiana v. City of Indianapolis*, 1311 N.E.2d 308, 315 (Ind. 1956)) and a prohibition against "recoupment of actual operating losses not foreseen in the original rate-making process" (*City of Muncie v. Public Service Commission of Indiana*, 396 N.E.2d 927 (Ind. Ct. App. 1979). Therefore, because Duke had not first gained Commission approval for these costs, the Court found the Commission lacked the statutory authority to grant Duke's relief.

Just as in *OUCC v. Duke I*, Duke incurred the January 1, 2019 through November 3, 2021 CCR costs without first obtaining Commission approval of those costs. Also similar to *OUCC v. Duke I*, these costs were incurred during a period for which rates, including depreciation expenses, were established in a prior base rate case (Cause Nos. 42359 and 45253). Like *OUCC v. Duke I*, Duke seeks recovery for these costs through updated depreciation expense.

OUCC v. Duke I appears to be at least partially founded on the idea of the Court that depreciation rates set in a rate case recover the cost of depreciation, including retirement obligations such as CCR, incurred until the depreciation rates are revised in a subsequent rate case. Pursuant to that view, retirement obligations such as CCR costs incurred during the period for which such depreciation rates are in effect are "recovered" through those depreciation rates and attempts to recover retirement costs such as CCR costs not included in those deprecation rates but incurred during their period in effect by later including them in future depreciation rates are acts of retroactive ratemaking. Given this analysis, we deny Duke's request to recover its January 1, 2019 through November 3, 2021 CCR costs.

b. Future CCR Costs. As to the future CCR costs, no party challenged the estimated costs presented by Company witness Hill and included in the decommissioning studies prepared by Mr. Kopp. OUCC witness Armstrong objected to the inclusion of contingency in the estimates, but, as we shall explain, we have long held that a reasonable contingency is appropriate in the inclusion of decommissioning estimates. There was initially some confusion regarding whether post-closure maintenance ("PCM") costs were included in the depreciation study sponsored by Mr. Spanos and filed with the Company's case-in-chief. However, the Company filed corrections clarifying that the PCM costs had been included in the depreciation study. Thus, the revised testimonies eliminate the confusion, and appropriately describe the PCM costs as being included in Duke's request in this proceeding. They are also supported by witness Kopp's decommissioning study set forth in Duke's Exhibit No. 37, Attachment 37-B(JJS). No party took issue with the Company's request to recover PCM costs or the accounting treatment proposed by Company witness Riley. As such, we find recovery of the PCM costs pursuant to the accounting treatment described by Mr. Riley is appropriate and should be approved.

c. Response to CAC's Criticism of Duke Coal Ash Closure Plans. CAC witness Dr. Frank made many assertions regarding the efficacy of the Company's coal ash impoundments closure plans and their relationship to this proceeding. She recommended the Commission require the Company perform a comprehensive evaluation of current and future costs for each of its coal ash disposal sites, so that the Commission can evaluate the cleanup methods that will best serve Duke's customers in the long run. She further made many ratemaking recommendations, including denying cost recovery for coal ash closure projects that conflict with state and federal regulatory requirements. Duke witness Mr. Hill responded to many of her assertions on rebuttal and stated that the CAC's recommendations would require Duke to re-assess the closure plans the Company has been working on since 2015 under IDEM oversight.

Ultimately, IDEM has already performed the comprehensive evaluation sought by CAC. As discussed at length by Mr. Hill, IDEM has either found the Company to be in compliance or is in the process of completing its evaluation. IDEM, with the authorization and oversight of the U.S. EPA, is tasked with ensuring closure plans comply with all state and federal environmental requirements. Dr. Frank appears to take issue with how IDEM and EPA choose to regulate these activities. This is not the Commission's role. As such, the Commission declines to adopt any of Dr. Frank's recommendations.

K. **Coal Ash-Related Insurance Proceeds.**

i. Duke Case-in-Chief. Company witness Hill testified regarding the Company's proposal for sharing coal ash-related insurance proceeds with customers. Mr. Hill described at a high-level the settlements the Company reached with AEGIS and AmRe. Mr. Hill testified the Company is proposing to credit retail jurisdictional customers with their proportionate share of the insurance proceeds, net of related expenses, through its future ECR proceedings. Mr. Hill explained that the Company's litigation is ongoing and testified to the extent there are additional proceeds recovered, the Company will similarly share those proceeds through its future ECR proceedings. Mr. Hill explained how the Company is proposing to calculate customers' proportionate share of the insurance proceeds. He testified Duke is proposing to first credit customers with the amount of the insurance policy costs that were included in retail rates at the time those policies were in effect then, after that credit, the Company will then ascertain its overall closure-related expenses incurred as a result of its past coal ash management and determine the portion of those costs included in retail customers' rates. Mr. Hill explained that once that is determined, the Company proposes to apply that proportion to its coal ash-related insurance proceeds.

ii. CAC Case-in-Chief. Mr. Inskeep asserted that Duke was unable to identify the amount of settlement payments that would flow to ratepayers under its proposal, and Duke admitted that it did not maintain business records going back far enough to be able to calculate the insurance policy costs that were in retail rates at the time that these insurance policies were in effect. Thus, according to Mr. Inskeep, it is unclear how Duke intends to implement its proposal. In addition, when CAC sought additional information through discovery concerning how Duke valued its insurance claims for purposes of these settlements, Duke invoked attorney-client privilege and refused to answer. Further, Mr. Inskeep recommended the Commission ensure that ratepayers are promptly credited the benefit of the insurance settlements, plus interest. He further recommended the Commission consider taking additional actions, such as disallowance of certain CCR costs, to address the inadequacy of Duke's settlements to date and the insufficiency of its insurance policies to limit ratepayer exposure to massive CCR liabilities.

iii. OUCC Case-in-Chief. Ms. Armstrong testified the OUCC opposes Duke's proposal to share insurance settlement proceeds with ratepayers, asserting that Duke's ratepayers should receive the full proceeds from these and future settlements. She noted that ratepayers previously paid for the premiums associated with these insurance policies in past rates and paid for these risks. Therefore, Ms. Armstrong reasoned, ratepayers bore the burden of the costs to address the risks which the proceeds now cover. By contrast, she noted Duke's shareholders bear no risk in this regard and therefore should not be given a windfall in the form of insurance proceeds. She argued it would be inequitable to deprive the party who paid for the premiums of the proceeds received as a result of the coverage purchased. She also noted that Duke's ratepayers are not receiving return of premiums where the risks insured against were not realized, and proceeds of insurance were not received.

Mr. Armstrong argued that although Duke's proposal attempts to address this issue by crediting ratepayers for these past premiums, those payments pale in comparison to the hundreds of millions in CCR costs Duke will recover from ratepayers. She asserted that these policies were not rescinded, and Duke should not now be permitted to enhance shareholder profit to the detriment of ratepayers. She noted that Duke's ratepayers are currently paying, and will continue to pay for several more years, significant CCR closure costs through rates, and these proceeds will alleviate the impact of these costs and address utility rate affordability.

She highlighted Duke's commitment in Cause No. 45253 S1 to provide any net proceeds from future insurance claims related to the CCR or IDEM Rule compliance to its customers to help mitigate the expenses of closure plans. She stated the Commission acknowledged this and required Duke to provide regular status updates on insurance claims in ECR filings. She criticized Duke for not providing updates in Cause No. 42061 ECR40 and Cause No. 46061 ECR 41 that it had reached these settlements with insurance companies and waiting until this rate case to inform the Commission and other interested parties of the settlements. She noted that because of this delay, Duke's ratepayers are unlikely to see the benefits of these settlements until 2025. She reasoned that since Duke has benefited financially from retaining these funds, it should also include interest in its calculation of the credit to appropriately compensate ratepayers with the full benefits of the settlements.

iv. Duke Rebuttal. On rebuttal, Mr. Hill testified the OUCC's and CAC's positions regarding the insurance proceeds ignore the fact that the Company has incurred prudent and reasonable coal ash closure costs that it cannot recover through rates. Mr. Hill testified given that this has occurred, it is reasonable for Duke to request in this proceeding to allocate the insurance proceeds between customers and the Company in the same proportion as the incurred coal ash closure costs are included in rates after also crediting customers with any insurance premiums previously paid through rates.

v. Commission Discussion and Findings. We find it reasonable for ratepayers to first be credited for premiums and costs recovered by Duke from ratepayers. We also find it reasonable for Duke to receive a proportionate share of the insurance proceeds for its reasonably incurred past CCR costs that are not recovered from ratepayers in Duke's proposed manner. We previously found the past CCR costs against which Duke seeks to apply the insurance proceeds to be reasonable in Cause No. 45253. The issues appealed in Cause No. 45253 did not address our determination about the reasonableness of the CCR costs. As such, our reasonableness determination remains.

We also find that granting the balance of insurance proceeds to Duke as noted above is consistent with *Citizens Action Coalition v. Public Serv. Co. of Ind.*, 552 N.E.2d 834 (Ind. Ct. App. 1990). In that case, the Indiana Court of Appeals considered the treatment of income tax losses that were generated as a result of the write-off resulting from the abandonment of the Marble Hill nuclear power plant project. There, the Court of Appeals held "[t]he customer [. . .] is not entitled to the tax benefits associated with the cancellation of a nuclear project" because the customer did not "contribute to the cost of the failed project." *Id*. at 839. Customers are not entitled to the benefit of insurance proceeds reimbursing prudently incurred costs the utility was not permitted to recover from customers. Since some CCR costs are recoverable and some are not, it is necessary to formulate a mechanism to allocate proceeds, net of related expenses. Duke has proposed a reasonable methodology that is based upon proportionality. Customers will receive the benefit of such proceeds in the same proportion as the incurred costs are included in rates after also crediting customers with the cost of insurance premiums that have been reflected in rates. This is reasonable and we approve it. As such, Duke is to propose a reasonable proportional sharing mechanism in a future ECR proceeding, taking into account the then-known recovery of incurred coal ash closure-related expenses, for commission review.

L. Deferral Accounting Treatment for Gibson Units 1-4. In its case-in-chief and as part of calculating its depreciation accrual rates, the Company proposed to extend the depreciable lives for Gibson Units 1–4 beyond their estimated retirement dates. This was done in an effort to mitigate the Company's rate request. As a part of that effort, the Company requested deferral accounting treatment for the remaining balance of Gibson Units 1–4. Company witness Lilly explained the regulatory asset treatment and testified that absent an unexpected event, the Company expects that every coal-fired steam generation unit will qualify as a normal retirement at its retirement. Ms. Lilly testified that so long as the Company has coal-fired steam generation in service, Duke will simply assign sufficient depreciation reserve to the property being retired. Ms. Lilly explained that upon retirement of the last unit remaining, this normal treatment would require the allocation of depreciation reserve across functions, which is not typical practice. As such, upon retirement of the last coal fired steam generation unit and in accordance with Ind. Code § 8-1-2-10, Ms. Lilly testified the Company is proposing that any remaining net book value in steam generation be deferred and amortized over the remaining assumed depreciable life to ensure full recovery of the cost of the asset and the cost of its removal. She testified that any deferred net book value and cost of removal will be included in the Company's rate base for ratemaking purposes. She further testified to the extent that any future retirement is deemed abnormal, the Company is requesting in this case for Commission approval to defer that net book value of the units that are retired and the cost of removal in the interim if any of those units are unable to be accounted for as a normal retirement. Ms. Lilly explained that in accordance with Ind. Code § 8-1-2-10, this regulatory asset would then be included in Duke's rate base in a future base rate proceeding, ensuring full recovery of the costs of the asset and its decommissioning costs.

With respect to cost of removal, Ms. Lilly testified the Company is proposing that upon retirement of the last coal unit, under the Company's proposal, the cost of removal embedded in accumulated depreciation will be recorded to a regulatory liability (also to be reflected in rate base for ratemaking purposes). Ms. Lilly explained that when all decommissioning is complete (including post-closure maintenance), the remaining balance will continue to be reflected in rate base for ratemaking purposes and will be amortized over a period of time to be determined by the Commission.

Ms. Lilly testified she believes the Company's requested deferral is reasonable, as the shift for environmental reasons from coal generation to other cleaner sources creates a unique situation that requires certainty from the Commission that the costs will be recovered, even if the Company is not able to account for the retirements using normal accounting. Ms. Lilly further testified that approving now the use of deferred accounting by the Company at the time of the coal units' retirement with assurance of continued cost recovery until all costs, including cost of removal, are recovered, provides a known path forward all interested parties can count on.

No party took issue with the Company's proposed deferral accounting treatment for the remaining balance of Gibson Units 1–4. The adjustment was voluntarily made by the Company with affordability for customers in mind. We agree with Ms. Lilly that the Company's requested deferral is reasonable, and we therefore find the proposal as set forth herein and Ms. Lilly's direct testimony is approved.

M. <u>GoGreen Program—Renewable Energy Credits ("REC") Supply Proposal</u>.

i. <u>Duke's Case-in-Chief</u>. Duke requests approval to begin utilizing RECs generated from the upcoming Speedway Solar purchase power agreement ("PPA") to satisfy GoGreen program subscriptions, once the site is operational. Company witness Sieferman explained these RECs would be sold to the GoGreen program at a price set annually based on average REC prices for the National Voluntary Wind/Solar REC market ("National Voluntary Market"). Ms. Sieferman further explained that any Speedway Solar PPA RECs remaining from the prior vintage year (in excess of GoGreen program demand) could be retired on behalf of all Duke customers.

ii. <u>OUCC Case-in-Chief</u>. OUCC witness Armstrong testified that while the OUCC does not take issue with the concept of transferring RECs from renewable PPAs or future renewable assets, she stated the transfers should be done at the appropriate market rate for the REC generating source. Ms. Armstrong testified that Duke stated it expects the Speedway Solar RECs will only be eligible for sale into the National Voluntary Market or the Ohio REC market, and that the Ohio REC market is currently planned to be phased out after 2026. Ms. Armstrong indicated that although Speedway Solar may not currently qualify for other REC markets, shed said States could always change their renewable portfolio standards ("RPS") to allow Speedway Solar or other Indiana-sited sources to qualify for compliance and eligibility to participate. She stated that the OUCC does not want to limit the price to the National Voluntary Market if Duke's RECs from PPAs or renewable generating assets become eligible to sell into another market at a higher value. She asserted Duke should be monitoring REC markets and their respective requirements and selling its RECs at the maximum price its sources can receive, and any RECs transferred to the GoGreen program should reflect this price.

Ms. Armstrong stated that if the highest market price would increase to a level that would be undesirable for GoGreen customers, then Duke should procure RECs from alternative sources to cover GoGreen customers' elected renewable energy usage. She also provided an alternative proposal through which Duke could sell RECs in its inventory at the highest market price possible, and the proceeds from this sale could then be used to purchase lower-cost National Voluntary Market RECs for GoGreen customers. As part of this alternative proposal, she stated that any sales to GoGreen customers associated with these REC purchases would then be credited to all ratepayers through the FAC, and GoGreen customers would also be responsible for any brokerage and retirement fees associated with REC purchases made using proceeds from the other Duke REC sales. She stated this would be a reasonable compromise to ensure all Duke's ratepayers receive the full value of RECs associated with renewable energy or generating assets they are paying for in rates while giving GoGreen customers access to lower-priced RECs.

Regarding Duke's proposal to retire any RECs not transferred to the GoGreen program, Ms. Armstrong testified that Duke's proposal would result in ratepayers forfeiting valuable offsets to the costs associated with the Speedway Solar PPA and future renewable PPAs and generating assets. She noted that since Indiana does not currently have a mandatory RPS, retiring RECs associated with all ratepayers' energy use is not mandated under current regulatory requirements. She reasoned Duke's proposal would be treating these RECs similar to how they would be treated under mandatory RPS requirements while sacrificing the benefits of REC sales for customers.

Ms. Armstrong addressed Duke witness Sieferman's claims that retiring these RECs reduces "greenwashing" concerns and allows all retail customers to claim solar in the residual mix. She stated that while it is true that Federal Trade Commission rules prohibit Duke from representing to its customers that it is supplying them with renewable energy if it sells the RECs associated with the energy generated from these resources, there are ways to communicate this information to customers without violating these claims. She testified that Duke can refer to the energy or capacity supplied by these resources as "null" energy or capacity. She also noted that if Duke is appropriately registering RECs, it should be able to track and demonstrate which RECs have been sold and which RECs remain in inventory.

She asserted the value gained in claiming the benefits associated with renewable energy must outweigh the loss of the monetary benefits of REC sales. She stated that in the absence of RPS or other compliance requirements mandating a utility obtain and supply customers with renewable electricity, this value is difficult to quantify monetarily and will vary for each person or entity receiving the benefits of such claims. She pointed out that since supporting renewable generation tends to have a positive message publicly, Duke's ability to claim it is supplying renewable energy to its customers is valuable to its public image. She noted the value to customers in claiming environmental benefits associated with renewable power likely differs among customers and customer classes. She testified that renewable energy claims are likely more valuable to large industrial or commercial customers with corporate sustainability goals and may be subject to new U.S. Securities and Exchange Commission ("SEC") climate risk disclosure requirements. On the other hand, she reasoned that residential customers may see these claims as an unimportant image-building endeavor and would prefer their monthly bill be lowered by selling the RECs associated with the electricity supplied to them. She argued Duke's proposal creates a situation where all ratepayers are subsidizing the costs of a service that is more valuable to a subset of customers. She noted that the GoGreen program is available for any customer who values claiming the renewable attributes associated with their electricity usage and serves as a reasonable option for this subset of customers.

Ms. Armstrong explained the SEC finalized new climate related disclosure requirements in March 2024. She testified the final rules require a registrant to disclose material climate-related risks, activities to mitigate or adapt to such risks, and information on any climate-related targets or goals that are material to the registrant's business, results of operations, or financial condition, and other items important for investors' assessment of climate-related risks. She noted the rule requires large, accelerated filers or accelerated filers that are not otherwise exempted to report their Scope 1 and Scope 2 emissions. She explained that Scope 1 emissions are direct greenhouse gas emissions from operations that are owned or controlled by a registrant and that Scope 2 emissions are indirect greenhouse gas emissions from the generation of purchased or acquired electricity, steam, heat, or cooling that is consumed by operations owned or controlled by a registrant. She indicated that one way a company's Scope 2 emissions can decrease is if its electric utility or electricity provider increases the amount of renewable generation it supplies to its customers. She acknowledged the SEC has stayed the effective date of the final rules pending the outcome of litigation from legal challenges to the rules.

Ms. Armstrong noted that by retaining and retiring these RECs, Duke can lower its Scope 1 emissions by claiming a greater percentage of its energy is supplied through zero-emission renewable generation sources. She added that since many of its larger customers likely qualify as large, accelerated filers, they would be able to lower their Scope 2 emissions if Duke can claim it is providing all customers with more renewable energy by not selling these RECs. She reasoned that both Duke and its larger customers subject to these disclosure requirements would benefit from retiring RECs as they would be able to report lower climate-related risks to their investors. She argued this risk would be socialized across all of Duke's customer classes to the detriment of residential and smaller customers that would benefit from the REC sales proceeds.

As to the potential value of RECs, Ms. Armstrong testified that Speedway Solar is expected to produce 426,000 RECs per year once it is online, but the GoGreen Program's total needs have not exceeded 55,000 RECs per year since 2020. She showed that if the recent average National Voluntary Market REC market price of $3.00/REC were applied, this would result in Duke foregoing over $1.1 million annually in REC proceeds. However, she indicated this foregone value is a conservative estimate, as some REC future vintages are nearly double this amount, and National Voluntary Market prices have reached as high as $7.00/REC within the last three years.

iii. Duke's Rebuttal. On rebuttal, Ms. Sieferman testified the Company proposed to use the National Voluntary market to price Speedway Solar PPA RECs for the GoGreen Program because there are only two markets in which the RECS can be sold—National Voluntary Market and the Ohio Renewables market – and the Ohio Renewables market is set to end in 2026. Further, she explained the Company proposed to set an annual price based on the 12 month average national voluntary wind/solar pricing because the Company plans to transfer RECs to the GoGreen program annually for the subscription portion of the program, and the specific number of RECs needed will be determined based on program enrollment and participation throughout the year.

Ms. Sieferman also responded to Ms. Armstrong's recommendation to avoid retiring RECs absent a mandatory RPS. Ms. Sieferman testified that Duke's testimony in Cause No. 45907 (the Cause in which the Commission approved the Speedway Solar PPA) explained the Company was considering holding and retiring RECs if that approach better aligned with the Company's environmental goals, and the Commission's Order in that Cause did not prohibit the Company's proposed treatment of the associated RECs. Further, Ms. Sieferman cited another Indiana utility that reserved its right to retire excess RECs in the absence of a mandatory RPS.

Regarding Ms. Armstrong's recommendation related to reimbursing customers for fees associated with retiring RECs, Ms. Sieferman testified RECs retired on behalf of all customers by the Company would be retired using a self-certifying process, therefore there will be no associated third-party retirement costs incurred. Ms. Sieferman testified the Company agrees with Ms. Armstrong that any costs associated with retirements of RECs used for the GoGreen program should be reflected in the GoGreen subscription fees and not recoverable from all retail customers via the FAC.

Regarding Ms. Armstrong's alternative proposal, Ms. Sieferman testified the proposal unnecessarily complicates the process and assumes there are more market options than currently exist for these RECs. Further, she stated Ms. Armstrong's proposal fails to maintain the flexibility for the Company to determine how best to use incremental Speedway Solar PPA RECs for the benefit of all customers.

Ultimately, Ms. Sieferman testified it is the Company's position that there is value to customers in being able to claim the environmental benefits associated with renewable energy and that those benefits should be considered when choosing between monetizing the RECs and using the RECs for customer renewable programs or retiring on behalf of customers. She testified the Company's proposal related to the GoGreen program is reasonable and should be approved.

iv. Commission Discussion and Findings. We agree with Ms. Sieferman that Duke's GoGreen REC supply proposal is reasonable because it is more reflective of the market in which Duke operates and provides value to customers. We therefore approve the Company's proposal for utilizing Speedway Solar PPA RECs for its GoGreen program via transfer of RECs at the 12-month National Voluntary Market average price, with the flexibility to sell, retain or retire excess RECs not needed for GoGreen, and using the FAC to reimburse all customers.

N. Electric Vehicle Issues.

i. Electric Vehicle ("EV") Rate. Walmart witness Lisa Perry recommended the Commission require the Company to work with interested stakeholders to develop a new EV rate specifically for third-party owned public-facing EV chargers and to seek Commission approval of such rate within six months following the issuance of the Commission's Order in this Cause. On rebuttal, Company witness Flick testified the Company appreciates the need to have programs, services and rates that position itself well to meet the demands of its EV customers. In response to Ms. Perry, Mr. Flick explained the Company's set of tariffs, including the time of use ("TOU") rate structure proposed in this case, and demand charges proposed in Duke's power rates, are intended to reflect cost-causation and recover the fixed cost of service from low load factor customers including those customers offering public electric vehicle charging. Mr. Flick explained the Company has an EV team to ensure it is prioritizing and developing the programs and services EV customers' need and demand. Mr. Flick explained the group works closely with him and the Company will continue this work as the electric vehicle market matures. Mr. Pinegar further testified that the Company supports collaboration with stakeholders, including public-facing EV charging station owners, and has no issue with working with these stakeholders to develop a program reflective of Walmart's request. Walmart's request pursued in such an atmosphere would provide a focused development opportunity as well as likely afford a more administratively efficient Commission review of any proposal produced by it. We nonetheless decline to adopt Walmart's recommendation at this time.

ii. DC Fast Charging. Duke seeks to include 17 company-owned fast charging locations in its test year rate base. As of the end of 2023, rate base included six completed stations for $3.7 million. As of the time of the filing of direct testimony in this proceeding, four additional sites were completed with the remaining seven expected to be operational by end of May 2024 ($2 million additional forecast, with $1.5 million awarded from the IDEM Volkswagen Environmental Mitigation Trust Program). In sum, the June 2024 rate base includes $4.2 million of investment, and net of depreciation, the revenue requirement reflects $3.9 million as of June 30, 2024 and $3.5 million as of December 31, 2025. In addition, Duke proposes using station revenues to cover the station cost of operations, including fuel, and if revenues exceed costs they will credit the excess to customers through the FAC.

Even though no party took issue with Duke's proposal, we deny Duke's request to include these assets in its rate base. We highlight, as we did in *Indiana Michigan Power Company*, Cause No. 45933 (IURC May 8, 2024), that the service provided by EV Fast Chargers to the general public is not a traditional service provided by a retail electric service provider. Ind. Code § 8-1-2-1.3(d) provides that, subject to certain provisions, a person that:

> (1) owns, operates, or leases EV supply equipment; and
> (2) makes the EV supply equipment available for use by the public for compensation, regardless of whether the person charges the public for such use based on:
>> (A) the kilowatt hours of electricity sold;
>> (B) the amount of time spent by an electric vehicle at a designated charging space; or
>> (C) a combination of both clauses (A) and (B);
>
> is not a public utility solely by reason of engaging in any activity described in subdivisions (1) through (2).

In this statute, the General Assembly distinguished the provision of electric vehicle charging service from the provision of electric service provided by a public utility. Said differently, the provision of charging services is not necessarily a service provision of a retail rate-regulated public utility.

In *Indiana Michigan Power Company*, we declined a utility's request to include fast charging capital costs as part of its revenue requirement. In reaching this determination, we first noted Ind. Code ch. 8-1-2.3 and the above language in Ind. Code § 8-1-2-1.3(d). We explained Ind. Code ch. 8-1-2.3 establishes an exclusive right for a retail public service provider to provide retail electric service in its Commission-assigned service area. We said considering Ind. Code § 8-1-2-1.3 in conjunction with Ind. Code ch. 8-1-2.3 shows that electric vehicle charging made available for use by the general public is not necessarily a retail electric service. We found that when considering the reasonableness of including costs of such non-retail services in the utility's retail rates, there should be a demonstration of an identifiable benefit to retail ratepayers, even when such costs are a relatively small portion of an otherwise reasonable settlement. We did not find such support in the record in that Cause.

Nor is there sufficient evidence in the current Cause to support Duke's request. The only benefit provided to ratepayers is the potential that "*if* the [electric vehicle] charging revenues received are more than what is needed to cover these costs, the excess revenues will be credited to customers" (emphasis added). Pet. Exhibit 4 at 47. We find such a potential benefit too ill-defined and speculative. Additionally, it is one thing to supply electricity to a business which delivers fast charging services to retail customers, it is quite another for a regulated utility to make investment secured by ratepayers to become both the supplier and retailer of fast charging services, expanding the scope of the traditional regulatory compact. We therefore deny Duke's request.

We add that rather than presenting iterations of the same program, Petitioner would be better served in its efforts to advance EV fast charging in its service territory by engaging in proactive distribution planning, developing robust interconnection policies to interact with third-party charging station developers, and considering the creation of an unregulated for profit entity to provide public fast charging services to its customers.

10. <u>Disputed Test Year Revenues</u>. The Company proposed eight pro forma revenue adjustments to the Forward-Looking Test Period as set forth on Duke's Exhibit 26, Attachment 26-C Schedules REV1 through REV 8. The only issue raised with respect to the Company's proposed Test Period revenues was the issue raised by Nucor regarding the Company's treatment of certain revenues associated with Nucor as non-jurisdictional in its cost of service study. We find Duke's proposed Test Period revenues and all pro forma adjustments proposed by Duke, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

A. <u>Nucor's Case-in-Chief</u>. Dr. Zarnikau raised issues regarding a special contract between Nucor and Duke which the Commission approved in Cause No. 45934. Specifically, he testified that Nucor's contribution to the Company's operating income is understated in the cost of service study. He testified that the Company's accounting adjustments removed certain revenues and costs from the revenue requirement and cost-of-service study ("COSS"). He noted that Duke made adjustments that moved revenues and expenses outside of jurisdictional review.

B. <u>Duke Rebuttal</u>. Ms. Sieferman testified that Duke removed the revenues at issue in a manner consistent with Ms. Diaz's testimony in Cause No. 45934 and that such removal is appropriate. Ms. Diaz testified that Duke's removal of non-jurisdictional revenues and expenses was warranted and that the Company's plan and rationale for removing these amounts for the power supply was set forth in her testimony in Cause No. 45934. She also testified that revenues and expenses removed in the revenue requirements model were for the power supply above Nucor's firm load. She testified that removal of the amounts that are considered non-jurisdictional results in only the jurisdictional amounts remaining in the revenue requirement model and cost of service study for Nucor. She noted the amounts that remain in the cost of service study are the applicable portions of the contract which are subject to pricing updates based on the rate setting in the retail rate case.

C. Discussion and Findings. We find that Duke's removal of the revenues at issue is consistent with the special contract between Nucor and Duke approved in Cause No. 45934.

Ms. Diaz explained in the current Cause why the removal of non-jurisdictional amounts is warranted in her rebuttal testimony filed in this proceeding. She stated that she provided such testimony in Cause No. 45934 as well.

The evidence establishes that Duke incorporated such removal into the current Cause pursuant to the special contract approved in Cause No. 45934. We therefore disagree with Dr. Zarnikau's testimony that Duke "unilaterally" removed these items from the COSS. Our Order in Cause No. 45934 indicates that Nucor and Duke negotiated the special contract at issue at arm's length. If Nucor had concerns with the treatment of the revenues at issue, it did not raise them at that time. Because Duke's removal of the non-jurisdictional amounts is consistent with the Commission's Order in Cause no. 45934, it is approved.

11. Disputed Test Year Expenses. In its case-in-chief, Duke proposed seven cost of goods sold-related pro forma adjustments and 14 O&M-related pro forma adjustments as set forth on Duke's Exhibit 26, Attachment 26-C, Schedules COGS2 through COGS8, and Schedules OM3 through OM16 respectively. With respect to these adjustments, the parties took issue with Duke's pro forma adjustments to update its base cost of fuel in this proceeding, its adjustment to reflect recovery of costs to achieve corporate restructuring savings, its adjustment to remove costs associated with other post-retirement benefits, its adjustment to reflect normalization of major storm costs, and its adjustment to add residential customer credit card fees to base rates. We will discuss each of these issues in this section. Otherwise, we find all pro forma adjustments proposed by Duke, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

Further, on rebuttal, Company witness Graft sponsored three adjustments to the Company's forecasted O&M expense. First, the Company removed $2,096,000 from test period O&M costs to achieve annual corporate restructuring savings reflected in the test period forecast. The Company withdrew its request to defer the total costs to achieve annual corporate restructuring savings of $6,289,000 as a regulatory asset and recover them over a three-year period. The Company removed this pro forma adjustment on rebuttal. Second, in the Company's case-in-chief it removed $10,667,000 from test period expenses to reflect a normalized level of outage costs. In responding to discovery, the Company became aware of an error in the calculation of the normalized level of outage costs. and corrected this error on rebuttal, resulting in an additional $782,000 reduction to test period expenses. Third, as the Company footnoted in Ms. Graft's direct testimony, it discovered there were expenses in the revenue requirement for advertising that did not provide a material benefit to customers as required by 170 IAC 1-3-3(A). Company witness Graft testified that the discovery was made too late in the process to correct before filing the case-in-chief; however, the Company committed to making an adjustment in its rebuttal testimony, and therefore removed $539,000 from test period expenses to correct this error.

The OUCC and intervenors also took issue with a number of Duke's forecasted test year expenses. Each of these disputed text year expenses are addressed in the following sections.

A. **Depreciation**.

i. Duke Case-in-Chief. Mr. Kopp explained the decommissioning study performed by 1898 & Co. for Duke regarding the cost of decommissioning and dismantling each of Duke's generating stations or battery units. He said the total decommissioning and dismantlement cost as determined by 1898 & Co., and reflected in the Decommissioning Study, was net of salvage value for scrap materials at each plant. The estimated total net decommissioning and dismantlement cost for Duke's generation facilities included in the study is $859,231,300 in 2023 dollars. He explained the methodology to conduct the study.

Mr. Kopp noted and explained the direct costs, indirect costs, and contingency costs included in the study. He explained that contingency cost includes unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and dismantlement activities. He also explained that there are uncertainties for any project and that contingency costs that result from the age of the Plants, limits on drawing availability, and the absence of detailed data for environmental remediation (such as identification of asbestos, lead based paint, soil testing around transformers, etc.), prior to preparation of these types of studies. He said contingency costs account for these unspecified but expected costs and are in addition to the direct costs associated with the base decommissioning and dismantlement known scope items. Like indirect costs, he noted that it is standard industry practice to include contingency costs particularly in planning-level cost estimates such as those presented in the Decommissioning Study. Mr. Kopp explained how contingency costs are developed. He said excluding these reasonably expected to be incurred costs by not including contingency costs will not give the full picture of decommissioning costs. If these costs are not accounted for in planning for future decommissioning, the costs will be passed on from the current ratepayers to future ratepayers. Duke's Exhibit 11, Attachment 11-A indicates that the contingency costs were calculated as 20% of the direct costs. Mr. Kopp noted that none of these costs include a cost escalation and are all estimates in 2023 dollars.

Mr. Kopp explained that indirect costs include costs expected to be incurred by the Company during the decommissioning and dismantlement process, which would be in addition to the direct costs paid to a demolition contractor. He said this includes, for example, the costs for staff of the Company providing oversight during demolition activities, as well as Company overheads, general and administrative costs, permits, construction services, security facilities, environmental monitoring, and the costs of construction management which include scheduling, monitoring and supervising the contractors who will be doing the actual demolition work. He said these costs are intended to cover such additional expenses as the relocation/modification of switch yard facilities where that is necessary. He stated indirect costs were determined as a percentage of the direct costs, as is a typical approach when preparing these types of cost estimates. The percentage of direct costs that was applied to determine the indirect costs was developed by 1898 & Co. based on its experience with past decommissioning and dismantlement estimates. Duke's Exhibit 11, Attachment 11-A indicates that the indirect costs were calculated as 10% of the direct costs.

ii. Industrial Group Case-in-Chief. Industrial Group Witness Brian Andrews testified that because this capital recovery occurs over the average service life of the assets, it is critical that an appropriate average service life be used to develop the depreciation rates so no generation of ratepayers is disadvantaged. Mr. Andrews explained that in addition to capital recovery, utilities also recover net salvage costs through depreciation rates. Mr. Andrews testified that net salvage is the value received from the sale or reuse of a retired asset minus the cost of retiring the asset. Mr. Andrews testified that negative net salvage, which occurs when the cost of removal is greater than the salvage value received as a result of retirement, is a significant component of Duke's depreciation rates and expense.

Mr. Andrews stated that Duke has greatly overstated its proposed depreciation rates and recommends adjusting the proposed depreciation rates which will, in turn, reduce the test year depreciation expense by $124.43 million. Mr. Andrews testified that Duke proposed depreciation rates increase test year depreciation expense by $286.3 million over the 2020 depreciation expense at the current depreciation rates. Moreover, Duke's depreciation study on plant balances as of June 30, 2023 shows a total increase of $260.75 million, or 46%, over the currently approved depreciation rates. Mr. Andrews noted that steam production plant depreciation expense accounts for $203 million (78%) of the $261 million increase. Mr. Andrews stated that his recommended reduction to Duke's proposed depreciation rates consists of three main adjustments.

First, Mr. Andrews recommended that the interim retirement curves used for Edwardsport be the same as those used for the other steam production plants. Mr. Andrews explained that Duke witness Spanos artificially shortened the depreciable life of Edwardsport with the use of extremely short interim retirement curves in an attempt to justify Duke's proposal to recover nearly all of the investment in Edwardsport by 2035, even though its retirement date is 2045. Mr. Andrews explained that the use of these shortened interim retirement curves significantly accelerates the depreciation expense associated with Edwardsport and is a driver in the significant increase to the production plant depreciation expense proposed by Duke. Mr. Andrews explained that if Duke had used the same interim retirement curve for Edwardsport that is used for the other coal plants, the assumption would be that 72% of Duke's plant at Edwardsport would remain in-service through 2045, as opposed to 22% under Duke's proposal. In support of his proposal that Duke use the same interim retirement curves for Edwardsport that are used with the other coal plants, Mr. Andrews noted that there are no firm plans to retire Edwardsport's gasification plant in 2035 and that Duke has not performed the necessary analysis to segregate the plant balances into groups based on 2035 or 2045 retirement dates. Furthermore, Mr. Andrews testified that even if Duke did segregate plant balances to isolate gasifier costs, he would recommend that Duke continue to recover Edwardsport plant balances through at least the expected 2045 retirement date for the facility to moderate the rate impact to customers.

Second, Mr. Andrews recommended extending the service lives used in calculating the depreciation rate used for Accounts 356 and 367, both of which relate to Underground Conductors and Devices. Specifically, he recommended a 5-year increase to the average service life for each account such that the average service life for Account 356 would be 70 years and 65 years for Account 367.

Third, Mr. Andrews testified that Duke is attempting to recover an excessive amount of costs for the demolition of its production plants through depreciation rates. Specifically, Mr. Andrews testified that Duke is attempting to recover $1.25 billion of escalated decommissioning costs for its power plants. Mr. Andrews noted that Duke witness Kopp estimated that the costs to decommission the plants, excluding the inventory, is $650.2 million, which is 176% higher than the estimate offered by Duke in its last rate case. Mr. Andrews recommended that the total costs for inclusion in current depreciation rates related to future decommissioning activities at Duke's production plants should be reduced to $820 million, which is a $431 million reduction from Duke's proposal.

Mr. Andrews explained that Duke's proposed increase in decommissioning costs is largely driven by environmental costs, such as $131.4 million in estimated landfill capping costs at the Cayuga, Gibson, Wabash River, Noblesville, and Edwardsport plants, $130.5 million to close the 3,000 acre cooling pond at the Gibson plant, and associated escalation costs. With regard to the Gibson cooling pond closure costs, Mr. Andrews explained that the most expensive component of the closure costs is associated with Duke's proposal to cover the pond with six inches of new topsoil. Mr. Andrews testified that at this point, Duke has not identified any legal obligation to do this work and thus, Mr. Andrews recommends that this line-item cost should be removed from Duke's decommissioning cost estimate for Gibson. Mr. Andrews explained that Duke should investigate other options for the closing of the pond before seeking to recover the costs of the project, plus escalation costs, from customers.

Mr. Andrews presented testimony regarding the $92.1 million in attributed to the Coal Ash ARO costs that Duke incurred between January 1, 2019 and November 3, 2021 at the Cayuga, Gibson, and Noblesville CT power plants. Given that we denied Duke's recovery of these costs, we do not address Mr. Andrews' testimony on this point.

Mr. Andrews also testified that Duke has overestimated the escalation of decommissioning costs. Mr. Andrews explained that the decommissioning cost estimates used in Duke's depreciation study are stated in 2023 dollars and are then inflated to the year of final retirement for use in the calculation of terminal net salvage rates. Mr. Andrews explained that in conducting this escalation procedure, Duke assumed a 2.5% inflation rate, which has no support and is excessive. Mr. Andrews explained that the Livingston Survey forecast, which was cited by Duke as support for its proposed inflation rate, has on average been 0.48 percentage points higher than the actual observed levels of inflation during the period it was forecasting. Mr. Andrews testified that given the current median estimate of consumer price index inflation is 2.25% and removing the average 0.48 percentage point forecast error, a more realistic inflation rate to utilize would be 1.77%. To be conservative, Mr. Andrews recommended that Duke use a 2.0% inflation rate, as opposed to the 2.5% inflation rate proposed by Duke, to escalate the decommissioning cost estimates to the retirement year for the purposes of calculating terminal net salvage rates. Mr. Andrews explained that a 2.0% inflation rate is consistent with the Federal Reserve's long-term inflation target.

Industrial Group witness Mr. Gorman supported Mr. Andrews' recommendations and asserted that the likely lowest-cost option available to address abandoned plant regulatory is securitization.

iii. <u>OUCC Case-in-Chief</u>. OUCC witness D. Garrett proposed several adjustments to the Company's proposed depreciation rates. Mr. Garrett testified the OUCC's proposed depreciation rates would reduce the Company's proposed depreciation accrual by $123 million, when applied to plant as of June 30, 2023. He further testified adopting the OUCC's proposed adjustments would increase the current annual depreciation accrual in the amount of $138 million.

Mr. Garrett testified the OUCC's recommended depreciation rates are based on the following issues: (1) removing indirect costs and contingency costs from Duke's decommissioning cost estimates; (2) removing the annual escalation rate from Duke's present value decommissioning cost estimates; and (3) adjusting the Company's proposed service lives for several of Duke's transmission and distribution accounts. He asserted that Duke's 10% for indirect costs and 20% for contingency costs are arbitrary. Mr. Garrett testified that if the Commission were inclined to reject a complete disallowance of contingency costs, he would propose the Commission limit the contingency costs to 10%, rather than the 20% proposed by the Company. He argued that the Commission should not allow Duke to include escalation costs because these future costs have not been discounted to present value.

Mr. Garrett took issue with certain portions of Mr. Spanos' recommended mass property service lives. He proposed changes to the service lives of four transmission and distribution plant accounts, specifically: Account 354, Towers and Fixtures; Account 356, Transmission Overhead Conductors and Devices; Account 365, Distribution Overhead Conductors and Devices; and Account 367, Underground Conductors and Devices. Mr. Garrett explained the "curve-fitting process" in which the best Iowa curve is selected to fit the observed life table curve through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. He testified that mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results, particularly when there is sufficient data available. Mr. Garrett stated that for each of the accounts to which he proposed adjustments, Duke's proposed average service life, as estimated through an Iowa curve, is too short to provide the most reasonable mortality characteristics of the account. He asserted his proposal is generally based on the objective approach of choosing an Iowa curve that provides a better mathematical fit to the observed historical retirement pattern derived from Duke's plant data, in addition to applying judgment to the analysis. Mr. Garrett ultimately recommended the Commission adopt the depreciation rates proposed on his Attachment DJG-2-3 to Public Exhibit 9.

Further, OUCC witness D. Garrett testified there is an error in the Company's depreciation study regarding the calculation of production net salvage rates related to the escalation factors, and therefore the approximately $92.1 million of CCR costs were escalated and double counted.

iv. <u>Duke Rebuttal</u>. On rebuttal, Mr. Spanos disagreed with the parties' recommendations regarding contingency and escalation. Mr. Spanos testified the Commission has already addressed the contingency and escalation issues raised by the parties in several other cases, and neither the OUCC nor Industrial Group provide any compelling reasons to overturn Commission precedent for contingency or escalation. He noted that contingency costs take into account the unanticipated costs that will occur when decommissioning a generating plant.

Mr. Kopp noted that the 10% of direct costs that was applied to determine the indirect costs and the 20% of direct costs that was used to develop contingency costs was developed by 1898 & Co. based on experience with past decommissioning and dismantlement estimates. He emphasized that contingency is not being applied simply because the costs might exceed the direct costs, but rather, they are applied to determine the most likely total cost of completing the project. As such, he said contingency costs are a critical component for estimating the cost of almost any large construction project, and especially one that is as large and complex as the demolition of a large power plant, including closure of CCR areas.

Mr. Spanos noted that all parties agreed terminal net salve should be included in depreciation. He stated that to equitably recover the full costs of the Company's assets, including net salvage, net salvage must be based on future costs because decommissioning is going to occur in the future. He noted that the Commission precedent dating to 2004 affirmed that decommissioning costs should be escalated to the future time at which the facilities would be retired. *See PSI Energy, Inc.*, Cause No. 42359 Order at 71 (May 18, 20024).

He also responded to Mr. Andrews' historical arguments that Mr. Andrews relied upon to support a 2.0% escalation rate. Mr. Spanos first noted that his estimate is based on more than just the Livingston Survey. Second, Mr. Spanos explained that the period of time reviewed by Mr. Andrews—early 1990s when inflation forecasts expected higher inflation due to the high inflationary period of the 1970s-1980s and the years that encompassed the Great Recession—likely overstates any forecast error. Mr. Spanos adds that looking at longer term inflation rates shows that there have been many years with higher inflation. As a result, simply assuming that a 2.0% inflation rate will continue into the future is not a reasonable assumption, as he noted has been the case in recent years. Mr. Spanos also noted that the Handy Whitman construction cost index supports a higher escalation rate than his proposed 2.5% rate.

Further, regarding the parties' recommendations to lengthen the service life estimates for certain transmission and distribution accounts, Mr. Spanos testified both witnesses' proposals are based primarily, if not entirely, on comparing mathematical results from the statistical life analysis, which they emphasize in the hope of achieving objectivity. He testified, however, that many of the estimates do not represent reasonable life cycles for the asset class. Mr. Spanos further testified that as explained clearly by depreciation authorities such as the National Association of Regulatory Utility Commissioners ("NARUC"), estimating service lives must necessarily include a component of informed judgment. He testified 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, as is the case with various proposals made by Mr. Garrett. Finally, Mr. Spanos testified Mr. Garrett's proposed changes to net salvage percentages to a total of eleven transmission and distribution accounts is arbitrary and does not follow any standard practice or depreciation concept.

Mr. Spanos also argued the life characteristics for Edwardsport are not the same as other steam facilities. Mr. Spanos testified Edwardsport uses IGCC technology, unlike any of the other steam facilities within Duke's jurisdiction. He testified the advanced technology used in IGCC plants like Edwardsport is more complex and not expected to have the same characteristics over long periods as compared to traditional steam technology. Mr. Spanos explained this leads to different operational characteristics, frequent maintenance requirements, and ultimately, different life characteristics to the other steam facilities. Further, Mr. Spanos testified Mr. Andrews did not properly update the interim or terminal retirements when he recommended changing the interim survivor curves for Edwardsport. Mr. Spanos explained that by increasing the lives of the interim survivor curves the terminal retirements would increase, decreasing the interim retirements which would cause the weighted net salvage to be quite different from what Mr. Andrews calculated.

Mr. Kopp addressed Industrial Group witness Andrews' recommendation to remove the total amount associated with placing topsoil over 3,000 acres of the Gibson cooling pond be removed from Gibson's decommissioning cost estimate.

Mr. Kopp said Mr. Andrews did not provide evidence to support his recommendation. Mr. Kopp stated the costs to cover the Gibson Cooling Pond are reasonably anticipated costs that should be expected as part of closure of the pond. Mr. Kopp stated that suitable final surface conditions need to be achieved to mitigate erosion. He explained that the Company has experience with the necessary costs incurred for closure of various process water and ash ponds at other facilities. Based on this experience with these projects, he said placing topsoil and seeding the area is the most prudent and cost effective means by which to achieve suitable erosion control. If topsoil is not placed over this area, then suitable vegetation cannot be established to prevent erosion, which is a necessary condition for the site until such time that it is redeveloped. It would be imprudent for the Company to ignore the cost simply because one party's witness believes them to be "excessive" or to leave the site in a condition that will allow for erosion to occur. Mr. Kopp argued that prudent practices extend beyond pure legal obligation and should include site safety, reducing public risk, and managing liabilities. He added that Duke intended to include costs in the Decommissioning Study to meet legal obligations and those that are prudent and necessary.

v. Commission Discussion and Findings. We understand depreciation studies are not one-size-fits-all types of endeavors. The process of determining the correct inputs to apply in a depreciation study requires professional judgement and opinions. We believe depreciation rates should be updated so the assets will continue to be depreciated until their actual retirement date. Depreciation study review helps to ensure depreciation rates do not over-recover the asset, resulting in a higher depreciation expense being recovered in rates to the detriment of ratepayers. We believe Duke's Depreciation Study accomplishes this and we approve of Duke's Depreciation Study as modified below.

a. Indirect Costs and Contingency Costs. The OUCC argues that the Commission should remove indirect and contingency costs from Duke's decommissioning study. We disagree. First, the costs are not arbitrary. It is reasonable to account for the unexpected. Mr. Kopp first explained how his firm estimated Duke's direct costs. He then stated that the percentages it used to calculate indirect costs and contingency costs were based upon real world experience and that the application of indirect costs and contingency costs is an industry practice. We note that Duke's contingency percentage is the same as what we approved in Duke's last rate case.

We have previously found (as we did in Duke's last rate case) that it is appropriate to include indirect and contingency costs. We do not find facts unique to the current Cause to support a deviation in this practice. Further, removing contingency costs could lead to intergenerational inequity that is not recovered as part of the full service value of the assets, as Mr. Spanos noted in rebuttal.

b. <u>Escalation</u>. The OUCC argued against the inclusion of escalation costs and the Industrial Group argued in favor of reduced escalation costs. The OUCC's argument against escalation costs is based upon an argument, in the OUCC's view, that escalation costs should be excluded because these future costs have not been discounted to present value. We have held previously that escalation costs are properly included in decommissioning costs and the OUCC has not provided an argument unique to this Cause as a basis to change course. Our view also supports fair intergenerational cost allocation. We therefore decline to adopt the OUCC's recommendation to exclude all escalation costs.

We also find Duke's 2.5% escalation rate to be reasonable. First, this percentage is the same as the percentage approved in Duke's last rate case. Second, we find Mr. Spanos' explanation for the 2.5% rate and his identification of historical weaknesses in Mr. Andrews' analysis to be persuasive. We agree with Mr. Spanos that a more specific price index, such as the Handy Whitman construction cost index he employed in his analysis, better represents expected escalation than the more general consumer price index.

c. <u>Survivor Curve</u>. The OUCC and the Industrial Group's next proposed adjustment was to alter the interim survivor curves for the Edwardsport facility. The Industrial Group believes the interim survivor curves for Edwardsport should be the same as for other steam facilities. The OUCC did not oppose the survivor curves utilized by Duke. Duke pointed to the fact that the advanced technology used in IGCC plants like Edwardsport is more complex and is therefore not expected to have the same characteristics over long periods when compared to traditional steam technology, leading to different operational characteristics, frequent maintenance requirements, and ultimately, different life characteristics than the other steam facilities.

We agree with the Industrial Group that Duke failed to provide sufficient evidence that it will actually shutdown Edwardsport syngas operations and the associated facilities in 2035. As Mr. Andrews identifies, the conversion is not yet certain, and no analysis was conducted by the Company to segregate the plant balances into groups connected to the 2035 gasifier retirement (IG Ex. 2, Attachment BCA-1). As discussed elsewhere in this Order, the flexibility of Edwardsport as a dual fuel facility presents a value that is not readily dismissed. Accepting the Industrial Group position also serves as an additional affordability-related mitigation not unlike that proposed by the Company in its treatment of other generation asset retirements and delayed cost recovery. We note that accepting the Industrial Group position does not deny the Company the recovery of any prudently incurred costs and we would consider any future Edwardsport depreciation adjustments in future rate cases when the sufficiency of a supporting analysis can be considered.

d. <u>Mass Property Service Lives</u>. The OUCC proposed to lengthen the service lives for two transmission and two distribution accounts. The Industrial Group proposed changes to one transmission and one distribution account. The table below indicates that for three of the four accounts Duke increases or proposes no change to the average service life from the current estimate. Thus, both the OUCC and the Industrial Group recommend the average service life and overall life cycle be increased.

Current and Proposed Life Estimates

Account	Current Estimate	Duke	OUCC	Industrial Group
Account 354, Towers and Fixtures	75-R3	80-R3	88-R3	80-R3
Account 356, Overhead Conductors and Devices	65-R2.5	65-R2	74-R2	70-R2
Account 365, Overhead Conductors and Devices	55-R0.5	45-R0.5	57-O3	45-R0.5
Account 367, Underground Conductors and Devices	55-R2.5	60-R2	68-R1.5	65-R2

The Industrial Group's and the OUCC's proposals are based primarily, if not entirely, on comparing mathematical results from the statistical life analysis, which they specifically characterize as achieving objectivity. However, we believe their approaches do not appropriately consider the mortality characteristics of the assets or other factors that should be considered.

Duke applied Iowa type survivor curves to calculate depreciation expense, along with utilizing the retirement rate method to analyze historical data, while the OUCC used a different approach. The OUCC approach promotes objectivity, but NARUC has stated that estimating service lives must include a subjective component, which Duke's approach incorporates.

Duke's proposal extends the life of the accounts longer than the current estimate. A longer service life is to the benefit of ratepayers because depreciation expense would be recovered over a longer period of time, resulting in a lower depreciation expense amount in rates. We believe the OUCC is utilizing a method not supported by NARUC. Based on the evidence, we support the service lives for the four disputed accounts as proposed by Duke.

e. **Mass Property Net Salvage.** The last adjustment proposed by the OUCC relates to net salvage estimates of the Deprecation Study. Duke pointed out the OUCC's net salvage proposal is based simply on reviewing available historical data. While this is an important part of net salvage estimation, it alone does not adequately account for what can be expected in the future. Since the goal of the analysis is estimating the expected net salvage that will be experienced in the future, consideration of other factors must be included in the process.

Duke stated the method of determining the net salvage estimates in the Depreciation Study not only incorporates analysis of historical net salvage data, but also includes consideration of company operations and expectations for the future, as well as trends in the electric utility industry. These sources inform the judgment that is then used in determining a realistic estimate of the future net salvage, rather than an estimate that is selected only on the basis of historical data.

The OUCC was the only party to propose changes to the net salvage percentages proposed. The OUCC recommends different percentages for four transmission, seven distribution, and one general plant account's net salvage percentages, detailed in the table below.

Table 3: Net Salvage Percentages

Account	**Current Estimate**	**Duke**	**OUCC**
Account 353, Station Equipment	(10)	(15)	(11)
Account 354, Towers and Fixtures	(30)	(40)	(33)
Account 356, Overhead Conductors and Devices	(60)	(70)	(63)
Account 358, Underground Conductors and Devices	0	(5)	(1)
Account 364, Poles, Towers, and Fixtures	(50)	(80)	(58)
Account 365, Overhead Conductors and Devices	(40)	(60)	(45)
Account 367, Underground Conductors and Devices	(25)	(30)	(26)
Account 368, Line Transformers	(20)	(25)	(21)
Account 369, Services	(25)	(30)	(26)
Account 370.2, Meters – AMI	0	(2)	(1)
Account 371, Installations on Customers' Premises	(10)	(15)	(11)
Account 390, Structures and Improvements	(10)	(15)	(11)

The OUCC's proposed changes do not follow a methodology supported by authoritative texts. Rather, the OUCC's proposal is to create a gradualism approach to the currently approved estimates without considering the amount of costs being deferred to customers in the future. The use of gradualism to the extent proposed by the OUCC will leave the recovery of a significant portion of net salvage costs to future customers and risk causing customers to pay for the costs of assets after they are retired. Thus, the OUCC's proposal will create an under-recovery going forward.

We approve the net salvage estimates provided by Duke. All parties agreed net salvage should be included in depreciation and the concept of including net salvage in depreciation rates. The OUCC proposed an approach that creates an under-recovery that would lead to intergenerational equity. Duke stated net salvage analyses are future forecasts and should include other considerations beyond historical indications of the data. We agree that the net salvage estimates contained in the Depreciation Study should include these other considerations.

f. **Gibson Cooling Pond.** We find Duke's costs associated with the Gibson Cooling Pond are reasonable and prudent, regardless of whether they are legally required. Further, we find Duke is entitled to recovery of these depreciation costs pursuant to Ind.

Code § 8-1-2-19 which mandates that "Depreciation rates under this subsection shall be calculated to recover a reasonable estimate of the future cost of removing retired assets of the public utility."

B. **Labor and Labor-Related Compensation.**

i. Duke Case-in-Chief. Ms. Caldwell explained Duke proposed to recover the incentive pay expenses at target levels that are directly assigned or allocated to Duke. Ms. Caldwell explained that compensation and benefits are important for the utility to attract and retain highly skilled employees to operate a safe and reliable electric system. She said the Company must compete with the marketplace to attract such a workforce. Ms. Caldwell stated Duke's attempts to provide its employees' total compensation (base pay and incentive pay) at the median of the market as compared to similarly sized companies, both within and outside of the utility industry. Ms. Caldwell further explained that based on the companies Duke benchmarks its total compensation against and the Company's peers in the utility industry, the market dictates that incentive compensation be included as part of that overall compensation package.

She described the manner in which Duke sets salaries based upon market data and described the utility's short-term incentive pay ("STI") and long-term incentive pay ("LTI") plans. She said all employees are eligible for STI and LTI is limited to employees in leadership roles. The STI pay component is variable and is based on performance. She explained LTI plans provide stock awards to the company's executives and leadership-level employees. Ms. Caldwell asserted this compensation is necessary to remain competitive in attracting and retaining leadership. She asserted that LTI plans help ensure the company's leadership is focused on the long-term, which provides a benefit to customers as a "as a financially strong company will have greater access to capital at a lower cost, which in turn benefits customers through a lower cost structure." Pet. Ex. 16 at 12.

Ms. Caldwell contended that Duke's incentive compensation plans are not pure profit-sharing plans as they include other metrics, "including safety, operational excellence, customer satisfaction, and reliable and efficient operations." Pet. Ex. 16 at 30. She argued the incentive compensation plans are part of the company's efforts to provide a market-competitive compensation package for all employees. She also concluded that the costs of the incentive plans are allocated to both customers and shareholders as customers would pay for the amounts up to target levels proposed to be included in rates and shareholders would cover any amounts in excess of the target levels. She contended that these incentive packages are necessary to attract and retain talent, which enables the company to provide safe and reliable electric service.

ii. Industrial Group Case-in-Chief. Mr. Gorman presented Attachment MPG-3 to IG Ex. 1 comparing Duke's last five years of actual incentive compensation to budgeted compensation. This attachment indicates that Duke was under target for STI for two of the five years, meaning Duke shareholders paid no part of the incentive compensation for those two years. For all five years, Duke shareholders only paid 4.1% of the total budgeted STI of $29.8 million. Similarly, Duke shareholders only paid 6.9% of the total budgeted LTI of $8.4 million. In other words, for the total budgeted incentive compensation over the 2019 through 2023 period, ratepayers paid $38.2 million of total incentive compensation—while shareholders only paid a total of $1.8 million over that period, or less than $400,000 annually. IG Ex 1, Attach. MPG-3. In

Attachment MPG-4 to IG Exhibit 1, Mr. Gorman noted that 55% of the STI and 80% of the LTI are tied to Duke financial goals, which he contended only benefit Duke shareholders. He said Duke's proposed incentive compensation totals $29.6 million, but $14.6 million of that amount is specific to Duke's financial goals. He recommended the removal of $14.6 million of Duke's proposed incentive compensation costs from cost of service.

Mr. Gorman argued that because Duke develops its cost of service using 100% of its targeted level of incentive compensation, shareholders will only be assigned a small portion of the costs relative to the benefits they receive, or the incentive compensation expense above the targeted level. As such, he argued that the Company's incentive compensation does not satisfy the Commission's standard for recovery that incentive compensation costs be shared between customers and shareholders. Mr. Gorman recommended the removal of $14.6 million, the amount of incentive compensation tied to the financial goals of the Company and/or its parent, of Duke's $29.6 million proposed incentive compensation costs from cost of service.

iii. **OUCC Case-in-Chief.** Mr. M. Garrett testified that, based upon a Duke response to OUCC Data Request 19.5, the utility included a total of $29.559 million for incentive compensation in the 2025 revenue requirement. [11] He recommended that the Company's incentive compensation expense be reduced by $16.9 million. He testified the Company's proposed recovery of 100% of the projected incentive compensation does not satisfy the three components of the Commission's standard, because the Company's request for full recovery of projected incentives does not constitute a legitimate sharing of costs between shareholders and ratepayers. He further testified that 100% recovery is unusual when compared with the treatment of these costs in other jurisdictions and is not consistent with the prior treatment of these costs in Indiana. Mr. M. Garrett also explained that financial performance measures in incentive plans can control the payout of the plans, which allows the utility to divert money included in rates to pay incentives to shareholders instead when earnings targets are not met, as happened with this utility in 2020. The Company also paid out substantially less than budgeted in 2023. He also presented evidence that regulators generally disallow incentive compensation tied to financial performance.

Mr. M. Garrett also testified on rebuttal that members of the Board of Directors receive an annual retainer fee, payable in cash and Duke Energy Corporation shares. He said for the 2024 and 2025 test years, the Company expects to be allocated $411,548 in total compensation for Duke's Board members with $182,910 in cash compensation and $228,638 in stock-based compensation. He recommended the Board of Directors' compensation expenses be shared between shareholders and ratepayers. Specifically, he recommended the Commission disallow 50% of the Board members' cash compensation and 100% of stock-based compensation allocated to the Company in this proceeding. As such, he recommended a revenue requirement reduction of $320,093.

iv. **Duke Rebuttal.** Ms. Caldwell testified in opposition to Mr. M. Garrett's and Mr. Gorman's recommendations to remove the portions of STI and LTI compensation tied to financial measures and achievement. She testified the Commission should reject the proposed adjustments as it did in the Company's last litigated rate case, Cause No. 45253, because both Mr. M. Garrett and Mr. Gorman request that the Commission depart from its holdings

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11 Mr. Garrett noted this amount is different than the $29,931,520 referenced in Duke's response to OUCC Data Request 3.06.

authorizing recovery of incentive compensation in multiple cases, without offering any new rationale for why that would be appropriate. Ms. Caldwell reiterated the Company's position that all incentive compensation up to target levels should be recoverable in rates. Further, she testified the Company has met the Commission's three standards required for incentive plan costs to be recovered in rates, and the OUCC and Industrial Group have not provided any meaningful argument for applying different standards in this case. In so stating, she applied the Commission's three standards as to whether a utility should recover incentive compensation and how, in her view, the Company is meeting those standards:

(1) *The Company's incentive compensation plans are not pure profit-sharing plans*. Ms. Caldwell testified the financial metrics are balanced by operational metrics such as customer satisfaction, safety and reliability.

(2) *The Company's incentive compensation plans do not result in excessive pay levels*. Ms. Caldwell referenced her direct testimony and testified Duke's compensation philosophy is to target total compensation, consisting of the combination of base pay and incentive pay, at the median of the market when compared to peer companies. Ms. Caldwell explained that whether it is through base pay or a combination of base pay and incentives, Duke must keep its overall compensation package competitive to attract and retain a competent workforce. She testified that the market dictates incentive compensation as part of the overall compensation package in the utility industry. Ms. Caldwell noted that neither M. Garrett nor Mr. Gorman testified the Company's overall pay level was excessive.

(3) *Incentive pay expense is shared between shareholders and customers, as the Company is asking for recovery at target levels*. Ms. Caldwell explained that this is the standard both Mr. M. Garrett and Mr. Gorman believe the Company has failed to meet. She discussed in her rebuttal testimony how the target levels of total STI and LTI is equivalent to approximately half of the maximum incentive opportunity and any amounts over target would be paid for by shareholders. Thus, she argued the Commission's third standard is satisfied.

Ms. Caldwell also responded to Mr. Garrett's recommendation concerning Board of Directors compensation. She testified that she does not believe the OUCC's disallowance related to Board of Director compensation expense is appropriate. She explained that, by law, the Company is required to have a Board of Directors and the costs of being an investor-owned utility, including Board of Director costs, are in fact costs of service. She testified it is not fair or reasonable to penalize the Company for merely being an investor-owned utility with attendant requirements to that corporate structure.

v. <u>Commission Discussion and Findings</u>. The Commission uses a three-part test for evaluating the amount of incentive compensation costs to be included in rates. The Commission recognized this established standard in Cause No. 42359, as follows:

> The criteria for the recovery of incentive compensation plan costs is well established. We will allow recovery in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in

> excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs.

Indiana Michigan Power Co., Cause No. 45235 at 62 (IURC March 11, 2020). Further, once the Commission determines an incentive compensation plan provides benefits to shareholders and ratepayers and finds it not to be excessive, an appropriate level of costs should be included for recovery from ratepayers who are benefited by these programs. *N. Ind. Pub. Serv. Co.,* Cause No. 43526 at 63 (IURC Aug. 25, 2010).

There is no dispute that Duke satisfied the first and second prongs of this test and we find the evidence supports such a position. However, Industrial Group witness Gorman and OUCC witness Wright argued Duke did not satisfy the third prong of this test. Duke witness Caldwell asserted that Duke met this prong because Duke's shareholders paid incentive compensation over the target amount.

We find that with respect to the third prong discussed above, there must be a meaningful contribution by shareholders to the extent the utility's incentive compensation is tied to performance metrics that are based on financial goals rather than utility performance. We agree with Industrial Group witness Gorman that Duke's historic average shareholder contribution of $400,000 is insufficient in light of the $14.6 million of incentive compensation based on financial goals, for the benefit of the Company but not ratepayers. Accordingly, we find that a $14.6 million reduction to Duke's $29.6 million proposed level of incentive compensation is appropriate.

C. Trade Association Dues and Fees.

i. Duke Case-in-Chief. Ms. Sieferman explained the Company requested $1,125,000 in trade association expense for the 2025 forecasted test period for various trade memberships.

ii. CAC Case-in-Chief. Mr. Inskeep recommended the Commission deny the Company's request to include trade association dues associated with the Edison Electric Institute ("EEI"), the Indiana Energy Association ("IEA"), and the Chambers of Commerce in its revenue requirement. Mr. Inskeep testified this adjustment would reduce annual trade association expense from $1,125,000 to $51,000, a reduction of $1,074,000. Mr. Inskeep testified that organizations like EEI, IEA, and Chambers of Commerce engage in highly political, advocacy-oriented, and influence activities, which could include funding outside political and charitable contributions, litigation, regulatory advocacy, advertising, and efforts to shape the public and decision-maker opinion, in addition to numerous other activities that principally serve the private business interests of the members rather than ratepayer interests. He testified that although the Company has excluded a small subset of these influence activities that fall within the narrow legal definition of lobbying, it has not separately accounted for or removed from requested revenue requirement all trade association dues associated with this type of contentious political and policy influence.

iii. OUCC Case-in-Chief. OUCC witness M. Garrett recommended the Commission disallow 50% of the Company's industry association dues. Mr. Garrett testified industry associations engage in advocacy for the utility industries and their owners and stated that until the Company can demonstrate its request for recovery of industry association membership dues relates to customer interests rather than lobbying and broader industry advocacy efforts, it is recommended the Commission disallow the Company's requested recovery of $215,000 of industry association dues.

iv. Duke Rebuttal. Ms. Sieferman stated that EEI membership offers training and development programs for utility employees. She said IEA membership provides Duke employees access educational opportunities and the opportunity to grow and develop through committee participation on topics including cybersecurity, safety, environmental and energy efficiency and conservation. She asserted the knowledge and professional development gained through membership and employee participation in IEA enables employees to provide more efficient and effective service to customers. She added that IEA and its committees also sponsor supplier diversity fairs which provide Duke with exposure to additional suppliers who may be able to more effectively provide services or goods to the Company at a lower cost.

Ms. Sieferman said Chambers of Commerce membership allows the Company a forum to hear from and share with business organizations critical information regarding utility business operations, including items such as rates, reliability, billing, electric fleet vehicle programs, products, and services. She explained that Duke's Chamber engagement provides a central point of contact for Duke's small and medium-sized business customers have no assigned Company liaison. She said these representatives serve in leadership roles with local Chambers gaining the pulse of the business community. Ms. Sieferman stated this better equips Duke to know the issues and evolving business needs of our customers so we can effectively respond to them. Chamber membership also supports the communities the Company serves, enhancing business attraction, business retention, and workforce development.

Ms. Sieferman also explained the Company included in revenue requirements only the non-lobbying portion of membership dues and fees. She stated amounts in the forecasted test period related to lobbying were forecasted directly to non-utility accounts and therefore were excluded from revenue requirements. She testified the Commission has approved the inclusion of trade association dues and fees such as these in the revenue requirement of other Indiana utilities, including in another base rate case, *Indiana-American Water Company, Inc.*, Cause No. 45870 (IURC Feb. 14, 2024). She stated the Company properly excluded the portion of these membership costs associated with lobbying in accordance with current FERC Chart of Account guidance, and the $1,125,000 amount of non-lobbying-related membership costs included in revenue requirements is reasonable, beneficial for customers, and should be approved for inclusion as proposed by the Company.

v. Additional Evidence Received at Hearing. In her rebuttal testimony, Ms. Sieferman was unable to provide specific examples of the types of benefits that she listed in her rebuttal testimony. She explained her inability to provide examples during her cross-examination testimony due to (1) not personally participating in the activities about which she was questioned, (2) her reliance on other individuals within Duke to help prepare her written testimony, and (3) not having at the witness stand with her a comprehensive list detailing the information.

Ms. Sieferman admitted on cross examination that she made no personal effort to verify whether EEI activities that EEI deems as non-lobbying are used for advocating for the interests of electric utilities. Similarly, she did not to verify whether IEA activities that IEA deems as non-lobbying are used for advocating for the interests of electric or gas utilities. Although an EEI publication describes the organization's activities as including "lobbying, advocacy, and regulatory proceedings," Ms. Sieferman was not aware of any examples of EEI's "advocacy" or "regulatory proceedings" as used in that text. Tr. H-61 – H-63; CAC Ex. CX-15 at 2.

vi. <u>Commission Discussion and Findings</u>. Trade association memberships are commonplace and are oftentimes useful for utilities. The associated costs are typically paid from a company's revenue. We are sensitive to concern that captive ratepayers may be funding utility industry lobbyists. Section 501(c) organizations like EEI are required to self-report the expenditure on lobbying activities and this is the proportion that has been deducted from cost recovery by Duke. Duke's removal of the U.S. Internal Revenue Service-sanctioned amount attributable to lobbying is based on historic levels identified by the trade associations. Here, the record demonstrates that the Company properly excluded the portion of these membership costs associated with lobbying in accordance with current FERC Chart of Account guidance.

Further, Ms. Sieferman, through her rebuttal testimony, provided examples of the benefits that the utility received as a result of these memberships. We acknowledge that on cross-examination she was unable to provide particular examples of these benefits, but she explained her inability to provide specific examples, which we find to be reasonable. Further, Ms. Sieferman did not change her testimony about the benefits of the trade associations. Accordingly, we find the $1,125,000 amount of non-lobbying related membership costs is reasonable and should be approved.

D. <u>Major Storm Expense</u>.

i. <u>Duke Case-in-Chief</u>. The Company proposed a pro forma adjustment to increase the amount of annual O&M expense for major storms in base rates from the current annual level of $12.7 million (as noted in in Duke's rebuttal evidence, this is the 2014–2018 average) to an updated annual level of $15.6 million (2019–2023 average). Ms. Sieferman explained this amount was calculated by averaging the five-year historical period (2019–2023) of Duke's major event day storm transmission and distribution expenses. Ms. Sieferman stated that in addition to establishing a normalized level in base rates, the Company is also proposing to continue to utilize the Major Storm Damage Restoration Reserve ("Major Storm Reserve") to track differences between the operating costs incurred and the amount collected in base rates in this proceeding. She explained that any under-recovery would be recorded as a regulatory asset and any over-recovery would be recorded as a regulatory liability. The net amount for the Major Storm Reserve would be addressed for recovery in the next retail base rate case. Ms. Sieferman asserted that it is appropriate to continue the Major Storm Reserve because this would help levelize costs associated with unpredictable major storms that vary year-by-year.

ii. **<u>OUCC Case-in-Chief</u>.** OUCC witness M. Garrett agreed with the Company's request to continue tracking the major storm costs and the recording of a regulatory asset or liability for future recovery. However, Mr. Garrett and OUCC witness Sanka disagreed with the $15.6 million amount the Company proposed for major storm costs to be recovered in base rates. Ms. Sanka asserted that 2023 is an outlier year, due to a significant rise in outage activity, as well as costs, due to the June 29, 2023, derecho that hit Duke's service territory. Therefore, Ms. Sanka proposed that the 2023 major storm expenses should be excluded from the five-year average and instead the annualized amount for transmission and distribution expenses related to major storms should be set on a four-year average of costs for the 2019 to 2022 period. The updated four-year average, per Ms. Sanka's calculation, would be $9.2 million instead of Duke's proposed $15.6 million, which is a pro forma reduction of $6.4 million to the Company's proposed pro-forma test year operating expense.

iii. **<u>Duke Rebuttal</u>.** On rebuttal, Company witness Sieferman explained why she disagreed with Ms. Sanka's recommendation to remove the 2023 costs from the normalized expense calculation. She noted that while the costs for 2023 were significantly higher than the costs in the other years, the costs for 2021 and 2022 were significantly lower than other years in the survey period. She testified such year-over-year variability led to the practice of averaging the results of a multi-year period to try to capture a more representative amount. Ms. Sieferman testified the updated annual level for major storms was calculated in the same manner as the $12.7 million amount approved in the Company's last base rate case in Cause No. 45253.

Ms. Sieferman further testified that Ms. Sanka's suggestions that the costs for 2023 are high and should be disregarded insinuates that these costs were not prudently incurred and should therefore not be recovered. Ms. Sieferman testified the storm significantly impacted the Company's service territory, and including an amount in the five-year average for these costs reflects the fact that costs for major storms will be more significant in some years than in others, and that including a higher level of costs over time results in smoothing out customer rates by collecting a little bit over a longer period to go towards these storms, rather than reflecting that full cost at once.

iv. **<u>Commission Discussion and Findings</u>.** We agree with Company witness Sieferman that it is most appropriate to update the annualized level of major storm expenses in the Company's base rates to reflect the five-year average of costs for the most recent calendar years of 2019 to 2023. The annual level of storms was calculated in this same manner in Duke's last rate case and we see no reason to deviate from this approach. Further, the record demonstrates storm expense can vary materially from year to year, and, as Company witness Sieferman noted, the fact there is such variability lends itself well to the practice of averaging the results of a multi-year period to try and capture a more representative amount.

We find that to remove the 2023 storm expense in its entirety from the 5-year average would not recognize the variability in storm damage from year to year, as the two years prior were below average. Given that storms are unpredictable year to year, especially regarding the severity and therefore costs incurred, we agree with Duke that a 5-year average continues to be a reasonable way to account for variability in storm expense.

For these reasons, we find it is appropriate to update the annualized level of major storm expense in the Company's base rates to reflect the pro forma level of $15.6 million, based on the five-year average for the most recent calendar years of 2019 to 2023.

No party disputed the Company's request to continue to utilize the Major Storm Reserve. We find the continued use of the Major Storm Reserve to track differences between the operating costs incurred and the amount collected in base rates in this proceeding is appropriate and should be approved.

E. <u>Rate Case Expense</u>.

i. <u>Duke Case-in-Chief</u>. The Company proposed a total rate case expense of $2,518,000, amortized over three years to produce an $839,000 annual expense.

ii. <u>CAC Case-in-Chief</u>. CAC witness Inskeep explained that Duke proposes total rate case expense of $2,518,000, amortized over three years to produce an $839,000 annual expense. He testified that the Company's rate case expense costs are not reasonable because the Company was under no obligation to file a rate case at this time. Mr. Inskeep further testified that the Company's rate case expenses are unreasonable to include in customer rates because these expenses do not benefit Duke's ratepayers. Rather, he stated due to the Company's proposed rate increase, these expenses are incurred primarily to benefit Duke's shareholders. Mr. Inskeep recommended that the Company's annual rate case expense be adjusted downwards by $839,000 associated with disallowing cost recovery of the rate case expense, or, in the alternative, the Commission should consider approving only a portion of rate case expense in recognition that many of these costs are driven by and benefit, at least in part, Duke's shareholders.

iii. <u>OUCC Case-in-Chief</u>. Mr. Eckert recommended that Duke's rate case expenses be amortized over a four-year period due to the length of time between Duke's previous rate case Order and the anticipated Order in the current case.

iv. <u>Duke Rebuttal</u>. Company witness Pinegar testified the Company filed the case because Duke's existing rates are "unjust, unreasonable, insufficient and confiscatory." Pet. Ex. 28 at 32. Further, he asserted the Company's rationale to file a rate case was guided, in part, by the requirement under Ind. Cod § 8-1-39-9(e) that a public utility must file a general rate case at least once during the TDSIC plan. Mr. Pinegar explained that the Company's filing of this rate case complies with this requirement and is part of a structured, regulated process designed to ensure that rates remain reflective of the costs associated with providing reliable utility services. Further, Company witness Lilly testified that under Ind. Code. § 8-1-2-63 it is contemplated that utilities will incur rate case expenses, and the Company's position is that it has reasonably included actual rate case expenses that are excessive. She testified Duke's request to amortize its reasonable rate case expense of $2.471 million over three years is consistent with the rate case expense ($2.413 million) and amortization period (three years) approved in Duke's most recent rate case (Cause No. 45253).

v. <u>Commission Discussion and Findings</u>. This Commission has, in the past, considered the propriety of rate case expense as a two-tiered test. The first level of inquiry is whether the item giving rise to the expense is reasonably necessary for the presentation of Petitioner's case. Assuming the satisfaction of the initial level of inquiry, then the next question is whether the expense incurred is reasonable in the light of the service provided. *Indiana Gas Co., Inc.*, Cause No. 38080 (IURC 9/18/1987), 1987 WL 357978. We find Duke met both of these prongs and that its expenses were reasonable. The Company has not filed a rate case in five years. We agree with Company witness Pinegar that both the TDSIC statute and the Company's rates dictate the need for the Company to file a rate case. Further, the record demonstrates that the amount Duke is requesting for rate case expense recovery is consistent with the amount the Commission found reasonable and approved in Duke's last rate case. In viewing Duke's rate case expenses in the current Cause individually and in light of this history, we find Duke's rate case expense to be reasonable.

This Commission has previously rejected invitations by the OUCC to allocate to shareholders rate case expense on previous occasions. See *Gary-Hobart Water Co.*, Cause No. 39585 (IURC 12/1/1993). We find insufficient evidence in the current Cause to determine otherwise.

While we approve Duke's rate case expenses, these expenses shall be amortized over a four year period, rather than three years as proposed by Duke, a length of time that aligns with the broader amortization period decided in this case, resulting in a decrease in the annual rate case expense amount of $209,833.

F. <u>Card Payment Fees</u>.

i. <u>Duke Case-in-Chief</u>. Mr. Colley explained residential customers may pay their Duke utility bills by check, money order, cash (via some walk-in payment locations), automated bank drafts, and electronic funds transfer without paying a fee. He explained Duke's costs for these payment methods are paid by all customers, regardless of how a particular customer opts to pay a bill, and are built into the utility's cost of service. He said residential customers who pay with a debit card, credit card, prepaid card, or electronic check (collectively, "Card Payment") are charged a $1.25 transaction fee (which was lowered from $1.50 per transaction in mid-2024), which is collected and entirely payable to a third party. While Mr. Colley described the efforts the Company has made to make Card Payment usage more affordable, he also provided examples of customer frustrations about Card Payment fees.

Mr. Colley testified that expanding the available fee-free payment options to include Card Payments would make payment options more inclusive for residential customers. On this point, he noted that individuals who rely on prepaid cards, receive their payroll or government benefits on a loadable card, or are "unbanked or underbanked," are isolated from fee-free payment options. He testified all customers currently pay for the utility's costs associated with other forms of payment and that it would be reasonable to treat card payments similarly. Ms. Graft explained the utility proposes to increase test period operating expenses by $2,621,000 to include card payment convenience fees in the Company's cost of service.

ii. <u>CAC Case-in-Chief</u>. CAC witness Inskeep testified he agreed with the Company's proposal to eliminate the current per-transaction fee associated with credit card payments. Mr. Inskeep testified convenience fees increase the effective cost of a ratepayer's utility bill, exacerbating affordability concerns. He testified that for example, low-income customers are less likely than customers overall to use more affordable payment methods when paying a monthly bill, meaning per-transaction charges on certain types of payment methods can have disproportionate impacts on low-income ratepayers and other vulnerable communities. Mr. Inskeep testified it is necessary and reasonable to remove per-transaction payment fees to eliminate any incidental barriers and disparate impacts that the fees are causing.

iii. **OUCC Case-in-Chief.** OUCC witness Latham recommended the Commission reject Duke's card payment fee elimination proposal because the proposal would unfairly shift costs to all customers, including those who do not use credit cards. Further, Mr. Latham testified that while customer satisfaction would likely be enhanced for those customers who would pay by fee-free card payment, the Company has not shown any value, including any level of enhanced customer satisfaction, for customers who pay by other means. He testified that if Duke desires to improve its customer satisfaction performance and help its most vulnerable customers, then he recommends Duke's shareholders absorb the cost of the fees the company wishes to include in rates.

iv. **Duke Rebuttal.** Mr. Colley testified he disagreed with Mr. Latham's claim that removing card payment fees would unfairly shift costs. He asserted the company's proposal would address a significant customer frustration and provide all residential customers, including some of the utility's most vulnerable customers, access to a fee-free payment option. He testified that by incorporating these fees into the general cost of service, the Company aims to provide equitable access to all payment methods, especially benefiting those who rely on this increasingly mainstream payment channel. Mr. Colley said the Card Payment fee removal would impact customer service, contrary to Mr. Latham's arguments, as evidenced by the consistent customer feedback that shows customer satisfaction is closely tied to the ease and affordability of available payment options.

v. **Commission Discussion and Findings.** The Commission has previously addressed similar proposals to provide a fee-free payment option in the Company's last rate case, Cause No. 45253 and in Indiana-American Water Company, Inc.'s ("Indiana-American") most recent rate case, Cause No. 45870. In both Causes, the Commission found the proposals unreasonable because the utilities failed to provide evidence to substantiate the value of eliminating the fees for non-participating customers. There similarly is a lack of such evidence in the current Cause. We therefore reject Duke's proposal to shift its credit card processing fees to all customers.

G. **Aviation Expense.** Duke indicated in its response to CAC Data Request 2.22 that it sought $1,904,614 in aircraft "costs related to maintenance, training, depreciation, etc." CAC Ex. 1, Attachment BI-3. CAC witness Inskeep recommended the Commission deny the Company's request to recover $1,904,614 for costs associated with private aircraft for transportation. Mr. Inskeep testified there is no way to verify the appropriateness of what appears to be a luxurious and extravagant method for travel by primarily non-Duke employees for inclusion in Duke rates. He testified there is no way to verify, for instance, that Duke executives have not used these aircraft for personal uses, to curry favor with policymakers and celebrities, or to engage in direct lobbying.

On rebuttal, Company witness Graft explained the aircraft Mr. Inskeep referenced are owned by Duke Energy Business Services, LLC and are used to serve all Duke Energy affiliates. She said such a sharing between affiliates is a cost-effective strategy that enables Duke to avoid needing its own discrete assets and service employees. As such, she explained, Duke only included 10.13% of the depreciation and 10.13% of other aviation expenses regarding these aircraft in the Company's 2025 forecast in this proceeding. Ms. Graft testified given Duke's relative size amongst Duke Energy affiliates, it is reasonable for Duke to include the 10.13% of the cost of these asset.

On cross-examination, Ms. Graft clarified that Duke did not provide a breakdown of aviation expense, in dollars, between operational purposes and employee transport. Ms. Graft admitted that there were zero times in 2022 and 2023, and only one time in 2021, when a Duke employee used the Company's transportation aircraft. Ms. Graft also admitted that the Company has not compared the cost of the transportation aircraft to the cost of commercial flights between Charlotte, North Carolina and Indianapolis. She also confirmed that Duke provided no information to the Commission to verify the individuals and types of travel for which the transportation aircraft were used.

We find Duke failed to justify the inclusion of its aircraft-related costs in its proposed revenue requirement. To be fair, the necessity to use private aircraft for transportation and patrolling of Company-owned assets is an expense one would expect a utility company the size of Duke to incur in the normal course of its day-to-day operations. However, Duke failed to provide sufficient evidence to justify these expenses, including a sufficient narrative of how it would use or has used the aircraft at issue and details to substantiate a proposition that its use of private aircraft was the most economical way for its employees, or those assisting Duke, to travel. Further, the lack of evidence prevents us from being able to appropriately conduct an analysis of the Five Pillars. Without sufficient evidence we simply cannot accurately assess the affordability prong of the Five Pillars. Thus, we find the Company's inclusion of its portion of the expenses for the shared use of the aircraft to be unsupported and we deny the cost recovery request.

H. <u>Investor Relations Expense</u>. OUCC Witness M. Garrett explained that Duke Energy maintains an investor relations unit to provide publicly available information in various formats to existing and potential shareholders in the investing community. These practices promote transparency between Duke Energy and the public and help Duke Energy build and maintain a positive reputation that encourages trust and promotes integrity. He added that Duke Energy allocated $709,569 of investor relations expense to Duke during the base year and Duke anticipates that Duke Energy will allocate $504,000 in the 2024 forecast period and $507,000 in the 2025 forecast period. Mr. M. Garrett recommended that the Commission disallow 50% of the investor relations expenses allocated to Duke based on his assertion that the responsibility to communicate with the global capital markets ultimately falls upon Duke Energy, not Duke or its ratepayers. As such, Mr. M. Garrett recommended a reduction in the amount of $254,000 to reflect this sharing of investor relations expense. He further asserted that investor relations costs are not a necessary cost of providing electric service, as evidenced by the hundreds of local electric utilities nationwide owned by cities, counties, and tribal nations that do not maintain an investor relations function.

On rebuttal, Company witness Bauer disagreed with the OUCC's proposed 50% disallowance of the investor relations costs because these expenses are necessary and required for Duke Energy to communicate with global capital markets in a manner that will attract capital. Mr. Bauer asserted it is reasonable to allocate a portion of these costs to Duke because its customers ultimately benefit from the parent company's ability to attract capital.

We agree with Mr. Bauer that investor relations expenses are a necessary and required cost in order for Duke to attract capital and that customers ultimately benefit from this. As such, we reject the OUCC's recommendation to disallow 50% of the investor relations expenses and find the full amount of investor relations expenses allocated to Duke is appropriate and should be approved.

I. <u>Other Post Retirement Benefits ("OPRB") Expense</u>. In its case-in-chief, the Company proposed to refund $75 million over two years, via the Company's Rider 67, from the Company's Grantor Trust. Further, the Company proposed a $5,850,000 pro forma adjustment in its case-in-chief to set the level of OPRB expense included in O&M to zero. Ms. Sieferman explained the adjustment was made because the level of external funding in the Grantor Trust, established to fund payment of future OPRB liabilities, was sufficient to pay these benefits in the foreseeable future without additional funding. Ms. Sieferman testified this treatment for cost-of-service purposes is consistent with that used in the Company's last retail base rate case, Cause No. 45253.

OUCC witness M. Garrett did not oppose the Company's proposal to refund $75 million over two years via the Rider 67 from the Grantor Trust. Mr. Garrett recommended, however, that the Company remove its pro-forma adjustment to set OPRB expense to zero because the Grantor Trust refund the Company proposed "will not necessarily eliminate the trust earnings in excess of the plan's cost." Pub. Ex. 2 at 26. Mr. Garrett also recommend that the amount refunded to customers be reviewed and trued-up at the end of the two-year period.

On rebuttal, Ms. Sieferman noted that the Company's proposal to set OPRB expense in base rates to zero was approved in the Company's last rate case. She explained that while Mr. Garrett's recommendation would, in effect, provide an additional credit to customers by decreasing expense by $5.85 million, this credit would need to come from Duke's general funds rather than from the funds in the Grantor Trust because distributions from the Grantor Trust are limited to OPRB payments and administrative expenses and taxes, not Other Post-Employment Benefit expenses. Ms. Sieferman testified that with this credit OPRB expense amount included in revenue requirements, other non-OPRB costs included in revenue requirements would not be fully covered by customer revenues, thus denying the Company the opportunity to earn its allowed return. Ms. Sieferman agreed with Mr. Garrett's recommendation to review the amount refunded to customers and true-up the amount at the end of the two-year period but maintained that adjusting the OPRB to zero as proposed by Duke is appropriate.

We agree with Company witness Sieferman that adopting OUCC witness M. Garrett's recommendation would effectively prevent the Company the opportunity to earn its allowed return. The Company's treatment of OPRB expense for cost-of-service purposes in this proceeding is the same treatment we approved in the Company's last rate case, and we see no reason to deviate from this treatment in this proceeding. As such, the Commission finds the Company's proposed pro forma adjustment of $5,850,000 to set the level of OPRB expense included in O&M to zero is reasonable and should be approved. We also find the Company's proposal to refund customers $75 million over two years from the Grantor Trust via the Company's Rider 67 is reasonable and agree the Company should review the amounts refunded to customers and true-up the amount at the end of the two-year period.

J. Late Payment Fees and Reconnection Charges.

i. Duke Case-in-Chief. Mr. Flick stated Duke proposed to increase its automated reconnection cost from $6.00 to $8.00 to reflect increasing associated costs. He also sponsored Tariff No. 5 which indicated the utility planned to maintain a $37.00 charge for manual reconnection for customers who opted not to use a smart meter. The Company plans on continuing its policy of charging late payment penalties of 3% of a net bill when not paid within 17 days following the mailing of the bill.

ii. CAC Case-in-Chief. CAC witness Inskeep testified that the Company's proposed increase to its automated reconnection charge and its late payment charges are unjust and unreasonable. He recommended that the Commission eliminate the reconnection charge and eliminate or reduce the late payment fees. Mr. Inskeep argued that it was unreasonable to require customers who have been involuntarily disconnected to pay customer service costs to reconnect their service while costs for other customer service calls are included in the revenue requirement and recovered from all customers. He noted that the Company stated in response to a CAC Data Request that the reconnection charge quantifies the costs of customer service representatives for disconnection calls for non-payment. He disagreed with asserting there are no, or only de minimis, costs "caused" by reconnecting the disconnected customer. He added that because reconnection is automated and remote, the Company experiences cost savings it would have otherwise expended in sending a truck or representative to visit the customer's home to reconnect service. Additionally, Mr. Inskeep testified that reconnection fees coupled with late fees exacerbate utility affordability issues in that a customer seeking to reconnect service would have to pay their past due bill, pay their late fee and pay the reconnection charge. Mr. Inskeep also recommends the Company eliminate or reduce its residential late payment charge or automatically waive the late payment charge in recognition that these charges exacerbate affordability challenges.

iii. Duke Rebuttal. On rebuttal, Company witness Colley argued the Company's long-standing and established late-payment fee policy is consistent with 170 IAC 4-1-13(c), which explicitly permits a utility to charge a late-payment fee. He contended that the late-payment fee both encourages timely bill payment and mitigates collection costs borne by all customers. Additionally, Mr. Colley testified the reconnection charge was designed to fairly and accurately recover reconnection associated costs; that is, the imposition of this charge ensures "the incremental costs related to reconnection are charged to customers who require this distinct action." Pet. Ex. 45 at 22.

iv. <u>Commission Discussion and Findings</u>. Regarding the reconnection charge, we note Duke's Data Request response that its reconnection fees are tied to its costs. We agree 170 IAC 4-1-13(c) permits a utility to charge a late-payment fee and the Company's late-payment fee policy is in accordance with this rule and we deny Mr. Inskeep's recommendation to eliminate or reduce the charge. Further, regarding the late-payment fee, we acknowledge that the Company significantly reduced the fee in Cause No. 45253. We agree with the Company the charge is necessary to ensure that the costs related to reconnection are charges to customers, and thus we find the fee is appropriate. Based on the evidence presented, we approve Duke's late payment fee and the reconnection fee.

K. <u>Payment Navigator Program</u>. Company witness Colley testified regarding the Company's proposed Payment Navigator Program. He said the Payment Navigator Program is intended to provided Duke's struggling customers a partner who will take additional time to explain the different ways the Company can offer support. He explained that through this program, a Duke representative will listen to customers to best diagnose why the customer may have fallen behind on their bill. The representative will tailor a unique set of recommendations to assist the customer in becoming current on payments and provides longer-term guidance for how to ease their electric energy burden. Mr. Colley said Duke included $350,000 in its forecasted O&M expense to implement and operate its new Payment Navigator Program to assist financially vulnerable customers.

OUCC witness Hanks recommended the Commission deny the Company's requested approval of the Payment Navigator Program and further recommended the Commission reduce Duke's pro forma O&M expense by $350,000. Mr. Hanks reasoned that the Company did not establish the necessity of the program, especially because these full-time staff (as he said Duke stated in a Data Request response) would mainly be used during high usage seasons. He further testified the Company's request did not consider the additional customer resources associated with the Customer Connect program.

We find the Payment Navigator Program is reasonable and provides an additional tool for Duke to support its financially vulnerable customers. As such, we find the costs associated with this program reasonable and are approved for inclusion in the Forward-Looking Test Period.

L. <u>Production O&M Costs</u>. Duke forecasted $21,425,540 in annual O&M expense for ongoing CCR handling and disposal costs. OUCC witness Armstrong testified that Duke failed to adequately show how O&M costs for its generating units' ongoing CCR handling and disposal were forecasted. She stated that although Duke provided some breakdown of these forecasted costs and the capacity factors in responding to the OUCC's data requests, Duke did not provide formulas, calculations or contract rates as to how these numbers were derived, despite the OUCC requesting this information twice. She testified that Duke stated the historical CCR costs were considered and then evaluated against the modeled capacity factors of the generating units, but this could not be verified without the formula showing how these capacity factors were applied to historical costs in calculating the test year forecasted O&M costs. Ms. Armstrong also noted conflicting information was provided in discovery with respect to the Environmental Health and Safety costs allocated to the budget. In the absence of this information, she recommended a four-year historical average be used to determine Duke's test year ongoing CCR handling and disposal O&M costs, which she provided confidentially.

Ms. Armstrong stated the four-year historical average for currently-operating generation units was calculated based on 2020–2023 data. She testified that she included the total values associated with the Cayuga, Edwardsport, and Gibson plants but after seeking additional information regarding the operating units listed in Duke's historical CCR costs, it was still not clear what costs were included in the DEI-Other category. Ms. Armstrong testified she was concerned there are non-CCR-related costs or CCR costs not related to ongoing operations that were included inappropriately; therefore, she did not include costs in the DEI-Other category. She noted that while she has the same concern that non-CCR related costs are included as non-recurring expenses, Duke's description of these costs shows they qualify as Environmental Health and Safety or other general administrative costs; consequently, she included the four-year average for historical non-recurring expenses.

On rebuttal, Company witness Hill disagreed with Ms. Armstrong's recommendation to reduce the O&M forecast for the 2025 test year by using a four-year historical average and disallowing the costs classified as DEI-Other. Mr. Hill testified the forecasted amount should not be reduced based on a straight-line historical average with a portion disallowed, as her proposed adjustments would inappropriately disallow reasonable costs the Company regularly incurs and expects to continue to incur going forward that were included in the 2025 forecast. Mr. Hill testified the forecast for the test year is based on historical actual costs and informed by capacity factor where applicable. He therefore recommended no changes to the Company's forecasted production O&M expenses.

We find that Ms. Armstrong's proposal to use a four-year historical average to determine Duke's ongoing CCR handling and disposal O&M costs would inappropriately disallow reasonable costs the Company regularly incurs and expects to continue to incur going forward. Mr. Hill testified the Company's forecasted test year costs are based on historical costs, informed by capacity factors, and we find this is a reasonable approach for purposes of forecasting these costs. As such, we find Duke's forecasted O&M expense of $21,425,540 is reasonable and should be approved.

M. Amortization Expense. Duke proposed nine pro forma adjustments related to depreciation and amortization expense in this proceeding as set forth in Duke's Exhibit 26, Attachment 26-C, Schedules DA2 through DA11. We have previously addressed the depreciation-related expense issues in the Depreciation section of this Order. Regarding the amortization-related adjustments, amortization expense was largely uncontested apart from certain issues raised by OUCC witness Eckert and discussed in this section. Otherwise, we find all pro forma adjustments proposed by Duke, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

i. **<u>Duke Case-in-Chief</u>.** In its case-in-chief, the Company proposed to amortize the following regulatory assets over a three year period: (1) COVID 19 deferred expenses; (2) remaining End-of-Life M&S Inventory for retired Gallagher; (3) 316(b) Plan Development costs (20% portion not recovered in Rider 62); (4) Purdue CHP Plant Deferred O&M Expense; and (5) 2024 Rate Case Expenses.

Duke deferred $4.844 million of COVID-19 expenses it incurred from March 2020 through March 2022.

ii. **<u>OUCC Case-in-Chief</u>.** OUCC witness Eckert raised several issues with the Company's proposal regarding these regulatory assets. Specifically, Mr. Eckert recommended these regulatory assets be recovered over a four-year period, not a three-year period as proposed by the Company. Mr. Eckert's position was that four years is reasonable because that is the period since the Company's last rate case order.

Further, Mr. Eckert testified the Commission should disallow recovery for Duke's regulatory asset for the $7.6 million in "unmonetized" remaining inventory after the retirement of Gallagher. He testified the remaining inventory was included in rate base in Duke's last rate case and Duke has been earning a return on this amount since its last rate Order and it has continued to collect this amount from ratepayers after the retirement of Gallagher. Mr. Eckert testified Duke has not provided evidence that reasonable inventory management routines were in place prior to that remaining inventory becoming obsolete. Mr. Eckert explained inventory is managed based on costs, lead-times and usage; when usage is expected to decline, inventory management techniques prescribe that safety stock should be decreased. He explained obsolete inventory often results from excess inventory that eventually cannot be used, and when very obsolete, it can no longer be sold or monetized and must be written off and disposed of.

Further, Mr. Eckert testified that the Company should not be authorized to recover its post-October 12, 2020 deferred COVID-19 costs because Duke's calculation of such expenses extended beyond the allowed period, which he contended ended on October 12, 2020, pursuant to the Commission's June 29, 2020 and August 12, 2020 Orders issued in *Indiana Office of Utility Consumer Counselor*, Cause No. 45380. Based on this analysis, Mr. Eckert calculated incremental COVID-19 expenses of $2,162,765.

iii. **<u>Duke Rebuttal</u>.** On rebuttal, Company witness Lilly testified the five regulatory assets at issue in this section of the Order are not included in rate base, and the Company is only seeking recovery of the deferred expenses over a three-year period. She testified the Company is opposed to extending the proposed amortization period to four years, and she disagrees with Mr. Eckert that a four-year amortization period is reasonable simply because that is the period since the Company's last rate case order. She testified there is a recent trend in the industry for more frequent rate cases, and the Company chose the three-year amortization period precisely because completing amortization of these assets before there potentially could be similar or other new expense-related assets to amortize in the next rate case is a priority.

Regarding Mr. Eckert's recommendation that the Company should not be authorized to earn a return on its deferred expenses related to the Gallagher's remaining M&S inventory, Ms.

Lilly reiterated the Company is requesting to recover the cost of the remaining inventory via an amortization and is not requesting a return on the inventory in this case. She testified Duke reasonably disposed of much of the remaining inventory leading up to and after the retirement of the Gallagher units and created the regulatory asset in accordance with the Commission's Order in the Company's last rate case. Thus, she testified it is appropriate for the Commission to approve the amortization of this regulatory asset as proposed.

In response to the OUCC's recommendation to disallow certain COVID-19-related expenses, Ms. Lilly stated that the June 29, 2020 Order issued in Cause No. 45380 provided for deferred accounting related to specific types of costs incurred starting on March 6, 2020, but with no specified expiration date. She stated any questions regarding recovery of Duke's regulatory asset should be regarding the prudency and reasonableness of it, in which she argued the regulatory asset is comprised of reasonable costs that no party objected to. She also stated utilizing an end date of March 2022, rather than October 2020 as proposed by Mr. Eckert, allowed Duke to take a longer view on its uncollectible expense, reducing that amount by around $5 million.

iv. Commission Discussion and Findings. The first issue we address is the appropriate amortization period for the above five regulatory assets at issue in this case—(1) COVID 19 deferred expenses; (2) remaining end of life M&S Inventory for retired Gallagher; (3) 316(b) Plan Development costs (20% portion not recovered in Rider 62); (4) Purdue CHP Plant Deferred O&M Expense; and (5) 2024 Rate Case Expenses. We initially note that Duke's prior rate case was filed in July 2019, nearly five years prior to the filing of the present rate case. Prior to that, Duke's rate case (PSI Energy, Inc. at that time) had been filed at the end of 2002. Therefore, the average time between Duke's last two rate cases and this rate case is approximately 10.75 years (the average of approximately five years and approximately 16.5 years. We have recently found rate case expense should be amortized over the historical average of time between Duke's rate cases. *See Ind. Amer. Water*, Cause No. 45870 at 83 (IURC Feb. 14, 2024). However, we find that the length of time between Duke's last two rate cases, which was based upon numerous factors, including economics, is an anomaly. Therefore, we find that lapse of time between those two rate cases should not be relied upon. We note that the length of time since Duke's last rate base case is more in line with today's prevailing industry norms. In light of this, we therefore find that the OUCC's recommendation of a four-year amortization is reasonable and appropriate.

Regarding the issue of the Gallagher Station's remaining M&S inventory, the record demonstrates this regulatory asset is not in rate base in this Cause, and therefore the Company is not earning a return on its deferred expenses associated with the M&S inventory as suggested by the OUCC. Duke is only seeking to recover the cost of the remaining M&S inventory via an amortization in this proceeding, and the record demonstrates the Company reasonably disposed of much of the inventory leading up to and after the retirement of the Gallagher units and created a regulatory asset for the remaining inventory in accordance with the Commission's Order in the last rate case. Thus, we find the regulatory asset the Company created for recovery of the remaining M&S inventory is appropriate and we approve the amortization of the regulatory asset as proposed by the Company.

We agree with Duke's analysis regarding COVID-19 accounting treatment. A review of the

Commission's June 29, 2020, August 12, 2020, and October 12, 2020 Orders in Cause No. 45380 shows that the Commission did not impose a specific end date to the COVID-19 accounting. Rather, the utility's expense is a question of reasonableness. Based on the uncontroverted evidence, we find Duke's expenses were reasonable. We therefore find the Company's proposed accounting treatment for its COVID-19-related expenses is appropriate and should be approved.

N. Tax Expenses. Duke proposed 16 tax-related pro forma adjustments in this proceeding as set forth on Duke's Exhibit 26, Schedule 26-C, Schedules OTX2 through OTX8; Schedule ETR; and Schedules TX1 through TX8. The only tax-related adjustment at issue in this proceeding is Duke's pro forma adjustment to normalize payroll taxes associated with major storms. We made findings previously in this Order on the O&M portion of this pro forma adjustment, and those findings apply here. Otherwise, we find all pro forma adjustments proposed by Duke, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

12. Net Operating Income at Present Rates. Based on the evidence and determinations made above, we find Duke's jurisdictional adjusted test year operating results under present rates are:[12]

Total Operating Revenues	$3,019,481,000
Operating Expenses	
Operation & Maintenance	$1,500,041,000
Depreciation and Amortization	$837,325,000
Taxes other than Income Taxes	$74,799,000
Income Taxes	$55,533,443
Total Operating Expenses	$2,542,402,000
Net Operating Income	$551,782,556

In summary, we find that with appropriate adjustment for ratemaking purposes, Duke's annual net operating income under its present rates for electric service would be $551,782,556. We have previously found that Duke's net original cost rate base as of the end of the test year is forecasted to be $12,481,993,000, that Duke's WACC is 6.19%, which would produce a return on net original cost rate base of $772,635,000. Duke's current return of $551,782,556 will be insufficient to represent a fair return on the fair value of its rate base. We therefore find that Duke's present rates are unreasonable and confiscatory.

[12] 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 capital, exclusion of DC Fast Charging locations in the test year rate base; adjustments to Edwardsport depreciation rates, rate case expense, revenue rate migration, credit card fees, and aviation expenses; as well as the related income tax impacts.

13. **Authorized Net Rate Increase and Rate Implementation.**

A. Rate Implementation Process. Company witness Graft described Duke's proposed rate implementation in this proceeding. With respect to the Step 1 rate adjustment, Ms. Graft explained the Company will calculate revenue requirements reflecting the June 30, 2024 capital structure, June 30, 2024 net plant in service and the associated annualized depreciation expense, and the 2025 forecasted amounts for other components of rate base. Ms. Graft testified the output of the Step 1 revenue requirements calculation will be provided to Company witness Diaz, who will calculate the Step 1 jurisdictional revenues by retail rate group. She explained the difference between jurisdictional revenues approved in the Commission's Order in this proceeding and the Step 1 jurisdictional revenues will be credited to customers in Rider No. 67 rates. Ms. Graft further explained the Company has forecasted the June 30, 2024 capital structure and net plant in service balance and the associated annualized depreciation expense for purposes of estimating the Step 1 impact in the case-in-chief. On rebuttal, the Company updated these estimated amounts to the actual June 30, 2024 capital structure and net plant in service balance and the associated annualized depreciation expense.

The Company proposed to implement its Step 1 rates, including base rates and tracker rates, as soon as possible following issuance of the Order in this Cause and upon submission of the compliance filing and Commission approval of the tariff. Ms. Graft testified the rates will be effective on a services-rendered basis. Ms. Graft explained that since the Step 1 actual net utility plant in service and capital structure will be known at the time a few weeks before the evidentiary hearing, there should be no need to schedule a defined period for the parties to review the Step 1 compliance filing. The Company estimated these rates would be effective in or before March 2025.

Regarding the Step 2 rate adjustment, Ms. Graft explained the Company will calculate revenue requirements reflecting its actual capital structure as of December 31, 2025, the lesser of the forecasted or actual net plant in service balance as of December 31, 2025, the annualized depreciation expense associated with the lesser of the forecasted or actual net plant in service balance as of December 31, 2025, and the 2025 forecasted amounts for other components of rate base. Ms. Graft testified the output of the Step 2 revenue requirements calculation will be provided to Company witness Diaz, who will calculate the Step 2 jurisdictional revenues by retail rate group. She explained the difference between jurisdictional revenues approved in the Commission's Order in this proceeding and the Step 2 jurisdictional revenues will be credited to customers in Rider No. 67 rates.

With respect to how the Step 2 rate adjustment will be implemented, Ms. Graft explained the Company will submit a second compliance filing with the Commission in March 2026 that will remove the Step 1 rate adjustment from Rider No. 67 and replace it with the Step 2 rate adjustment. She testified the Step 2 rate adjustment will take effect upon submission and approval by the Commission on an interim-subject-to-refund basis pending a 30-day review process and the resolution of any potential objections. Additionally, as was approved in Cause No. 45253 for the implementation of the Step 2 rate adjustment, Ms. Graft testified the Company is proposing to collect the difference between the Step 1 rate adjustment and the Step 2 rate adjustment, with carrying costs at the December 31, 2025 actual weighted average cost of capital, from January 1, 2026 until the time the Step 2 rate adjustment is reflected in Rider No. 67, expected to be in March

2026. Ms. Graft explained the Company's second compliance filing will include an estimate of this differential in the calculation of the overall Step 2 rate adjustment using actual (or estimated) kWh sales for services rendered January-February 2026. Ms. Graft testified that the development of the overall Step 2 rate adjustment in this way will have the practical effect of the Step 2 rate adjustment being implemented on January 1, 2026, on a services-rendered basis even though mechanically, the revised Rider No. 67 rates will be implemented on a bills rendered basis upon Commission approval.

OUCC witness Eckert requested the Commission find the Company's base rates should be implemented on a services-rendered basis, and Ms. Graft confirmed on rebuttal it is Duke's intention to do so. Further, Mr. Eckert recommended the Commission grant the parties at least 60 days to review the Company's compliance filing with updated rate base and capital structure. Ms. Graft interpreted Mr. Eckert's recommendation as being applicable to only the Step 2 compliance filing, as the Company provided the actual net original cost rate base and capital structure as of June 30, 2024 for the basis of Step 1 in its rebuttal testimony. Therefore, Ms. Graft explained there is no need for a review period following the Step 1 compliance filing. She testified the Company believes the 30-day period it has proposed for review of its Step 2 compliance filing will provide adequate time and requested the Commission approve this proposal.

Apart from the two issues raised in OUCC witness Eckert's testimony, no party took issue with Duke's proposed two-step rate implementation proposal. The Company confirmed on rebuttal its intention is to implement new rates on a services-rendered basis, and thus there is no disagreement between the parties on this issue. Further, we agree with Ms. Graft that a 30-day review period for Petitioner's Step 2 compliance filing is appropriate, and that review period is not necessary for the Step 1 compliance filing. Ultimately, we find Petitioner's proposal for implementation of Step 1 and Step 2 rates as set forth in Ms. Graft's direct testimony (Pet. Ex. 3) is reasonable and should be approved.

B. Authorized Rate Increase. Based on the evidence presented and subject to the approved compliance filing process, we find that Duke should be authorized to increase its rates and charges in two steps, calculated to produce combined additional operating revenue of $295,678,000 at the conclusion of the test year, resulting in total operating revenue of $3,315,159,000 before the effect of changes in ongoing tracker revenue discussed elsewhere in this Order.[13] This revenue is reasonably estimated to afford Duke the opportunity to earn net operating income that is no more than the fair return of $772,635,000 that we have found to be appropriate, based upon projected test year end rate base and capital structure. The rate increase shall take place over the two steps we have described and, subject to the compliance filings, shall be calculated to produce jurisdictional operating revenues and net operating income at each step as follows:

[13] 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 capital, exclusion of DC Fast Charging locations in the test year rate base; adjustments to Edwardsport depreciation rates, rate case expense, revenue rate migration, credit card fees, and aviation expenses; as well as the related income tax impacts.

(dollars in thousands)	Step 1	Step 2	Total
Rate base at original cost	12,005,252	476,741	12,481,993
Rate of return	6.08%		6.19%
Required net operating income	729,919	42,716	772,635
Less: pro forma net operating income at	518,605	33,178	551,783
Net operating income deficiency	211,315	9,538	220,853
Gross revenue conversion factor	1.33880		1.33880
Revenue deficiency before effect of	282,908	12,769	295,678
Pro forma revenues at present rates	3,019,481		3,019,481
Total revenue before effect of trackers	3,302,389	12,769	3,315,159

14. Cost of Service and Rate Design.

A. Cost of Service.

i. Production and Transmission Demand Allocation.

a. Duke Case-in-Chief. Duke proposed to changes its historic four coincident peak ("4CP") method of allocating demand-related production and transmission costs to a 12 coincident peak ("12CP") methodology. Ms. Diaz explained that the allocation of production costs refers to all production facilities including steam generation, hydraulic generation, and other production necessary to integrate that generation into the power supply system and deliver it to the bulk transmission system. Ms. Diaz stated Duke's 12CP peak period average was the coincident peak in each of the 12 months ended August 31, 2023, based on the Company's production peaks. From the historical data applicable to this rate case, load research supplied the retail demands by detailed rate code as included in the cost of service study for the 12-month period ended August 31, 2023.

Ms. Diaz noted FERC primarily relies on three system demand tests when determining which coincident peak method is supported by the record. She explained that there is not a steadfast rule for determining which demand allocation is appropriate and that the FERC tests are a consideration along with other decision points. She stated that although the results of each of these tests supported the use of the 4CP method, Duke opted to use the 12CP method based upon two factors.

The first factor was a concern about affordability. Ms. Diaz explained that had the 4CP methodology been selected, the residential rate increase would have exceeded 20%. She further explained that the Company does not seek to significantly impact one class of retail customers' rate increases such as weather-sensitive residential customer classes, while unduly benefitting other classes of customers due to the occurrence of extreme weather in a single peak period impacting the calculation of the demands which are limited to only four peak hours of demand. Instead, Ms. Diaz explained the Company aims for gradualism of the rate changes across the classes in its rate cases, and the use of the 12CP demand allocation for production and transmission accomplishes that objective for this retail rate case. She testified that affordability is a critical metric for Duke and will continue to be important for the Company as it focuses on attracting and maintaining customers in its service territory.

Ms. Diaz stated a second factor that influenced Duke to select the 12CP method was MISO's 2022 change from determining adequacy of resources on a seasonal (summer, fall, winter, spring) basis to an annual basis. She stated that Duke installs its transmission facilities to maintain its reliability constant throughout the year such that 4CP peak demands are not of any greater importance than any of the other monthly coincident peak demands, thus also supporting the use of a 12 CP for the transmission function.

b. <u>CAC Case-in-Chief</u>. CAC witness Dr. McCann testified that the allocation of generation costs should be split between capacity for reliability purposes and assets used to produce energy. He presented Table RJM-2 in CAC Exhibit 2 which showed the separation of the Company's proposed generation asset annual revenue requirement between reliability capacity production demand and production energy functions. Dr. McCann explained the revenue requirements are the sum of the target return on investment from the generation assets plus depreciation. He further explained the calculation for separation for reliability and energy purposes is based on the MISO CONE benchmark value of $98.59 per kilowatt-year plus a 15% reserve margin adder multiplied by the installed megawatts of Duke's portfolio capacity, which is 6,313 MW. He testified that the reliability capacity portion, which is allocated based on the 12CP production demand method, is 62.5% of the total generation asset revenue requirement, while the residual 37.5% is allocated based on production energy delivery. Dr. McCann recommended that, should the Commission disagree with Witness Inskeep and Witness Frank's recommendations to deny recovery of a substantial portion of Duke's coal ash costs, coal ash management costs should be recovered via the production energy allocator. He explained that because coal ash is produced in direct proportion to the energy generated and coal plants are not meant to meet peak load, allocating costs of burning coal by either the 4CP or 12CP method is inappropriate because those methods presume the primary purpose of that capacity is to meet peak demand rather than to produce energy around the clock; only the production energy or sales allocator should be applied. He also recommended that energy-related capital and operating costs should be allocated among customer groups based on production energy to reflect how it is used. He further recommended that the remaining generation capital costs, as well as transmission costs, should be allocated based on the 12CP method, which better reflects market operations in MISO than the previous 4CP method.

c. <u>Industrial Group Case-in-Chief</u>. Mr. Collins testified that based on the characteristics of the Duke system and the cost allocation method previously approved by the Commission in Duke's last base rate case, he recommended the continued use of the 4CP method. He testified there has been no material change in operational circumstances since that Order was issued to warrant a change. Further, he testified that comparing the 2018 load pattern and the 2022 and 2023 load patterns, Duke's system exhibits more of a 4CP now than it did in 2018, which was the basis of the Commission decision to approve the 4CP method in Cause No. 45253. Additionally, he pointed to the Company's 2021 IRP for capacity planning to conclude that 4CP allocation is appropriate. He noted that Duke witness Diaz admitted that Duke's system failed all three standard FERC tests associated with a 12CP allocator. Mr. Collins also contended that the 12CP method is not reflective of cost causation since off-peak months are not the cause of Duke's capacity requirements. Mr. Collins stated this indicated Duke remains a dominant 4CP utility, even more so than it was in the previous rate case.

d. Nucor Case-in-Chief. Nucor witness Zarnikau reviewed the Company's COSS and disagreed with the Company's use of a 12CP methodology. He recommended that the Commission follow the 4CP method as was used in the Company's last rate case, noting the Commission's grounds for doing so. He noted that cost causation principles and the Commission's findings in the previous rate case support the continued use of 4CP allocations of production and transmission demand related costs. Dr. Zarnikau also noted that the 12CP approach failed all three FERC tests concerning allocation of production and transmission demand related costs and he asserted the Company has not offered a compelling reason for proposing a 12CP method. Dr. Zarnikau also testified that concerns regarding data distortion created by Winter Storm Elliott for December 2022 could be addressed in several ways and recommended the easiest and most practical way would be for the Company to remove the month impacted by Winter Storm Elliott from the set of months used to calculate the average of the class coincident peaks. Additionally, Dr. Zarnikau disagreed with the Company's use of a 12CP allocation to mitigate the proposed rate increase to the Residential Class and stated that adjustments to implement gradualism can be applied post cost allocation if rate impacts necessitate mitigation.

e. OUCC Case-in-Chief. Dr. Dismukes testified that he disagreed with the Company's classification of fixed production costs as exclusively demand-related. He argued against the Company's allocation of production costs because the Company's assumption is inconsistent with the dual role production/generation assets play in serving both peak demand and low-cost energy requirements for off-peak periods on the Company's system. He testified that equally important is the fact that the Company's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets, which provide very limited capacity benefits and should not be exclusively classified as demand related. He then discussed what he believed to be the shortcomings of the Average & Excess method and provided support for the Average and Peak method. With that, he recommended the Commission rely on the results of his alternative COSS, which (1) classifies 50% of costs associated with the Company's renewable generation assets as fully energy-related, and (2) uses an Average and Peak method to classify the remaining production plant costs based on the Company's observed test year system load factors. His proposed classification method classified 42.5% of the Company's production plant costs as being energy-related, with the inverse (57.5%) classified as demand related for the test year. He also offered an alternative COSS where he used the 12CP method for production and transmission costs.

f. Walmart Case-in-Chief. Ms. Perry explained that Walmart appreciates the reasons the Company is proposing to move away from a 4CP production cost allocator, but she believes that shifting from 4CP to 12CP will create interclass subsidies through higher load factor customers paying a greater share of the fixed production costs than what is needed to meet those customers' contribution to the system peak. She testified that the Company's analysis of the three FERC system demand tests do not support moving to a 12CP cost allocation methodology. Ms. Perry testified that Walmart recommends that the Commission reject the Company's proposed 12CP production cost allocator and instead approve the current 4CP production cost allocation methodology for the Company's fixed production plant costs.

g. CAC Cross-Answering Testimony. Mr. Inskeep responded to testimony provided by Mr. Collins, Dr. Zarnikau, and Ms. Perry. He asserted that these witnesses place undue emphasis on the outcome of three tests created by FERC. He stated that while these tests can be informative, they rely on somewhat arbitrary thresholds and are not determinative of the cost allocation methodology that the Commission must adopt.

First, he noted that in approving a utility's change to the 12CP cost allocation method over various objections, FERC explained that its three peak load tests "are not a bright line test." CAC Ex. 5 at 5 *quoting PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,041 (2019). Second, he noted Duke's system passed the Average to Annual Peak test in every year of 2020–2023. He contended this means that the results of the historic base period (the 12 months ending August 31, 2023) which indicate that the system did not pass are anomalies and are not actually representative of Duke's annual peak characteristics. He added that Duke's system passed the On and Off-Peak Test in three out of the past four calendar years, in contrast to not passing the threshold for the base period used by Duke. Mr. Inskeep also said that the Low to Annual Peak Test is the only test that Duke does not pass in most years, although its four-year average (63.8%) is close to meeting the 66% or higher threshold, and it did pass in 2021. He said Duke's three tests results were consistent with a 12CP, not a 4CP, cost allocation method in its prior rate case. He also asserted that these results underscore the shortcomings of relying on historical data for a single 12-month period that is not weather-normalized and that does not consider forecasted peak load usage in the actual test year. Further, he said the 4CP cost allocation can also experience far greater swings in between rate cases as a result of one extreme weather event in one peak month, as Duke explained with respect to Winter Storm Elliott's impact in its base historic period.

He asserted Industrial Group witness Collins, OUCC witness Dr. Zarnikau, and Walmart witness Perry did not provide a justification or evidence supporting their claims that Duke has four "peak" months that are representative or indicative of cost causation for cost allocation purposes. Mr. Inskeep stated that he said Duke's system does not display a consistent set of four months that consistently experience higher usage than other months of the year. He stated that Duke cannot be expected to meet peak load in four specific months as its actual experienced four highest monthly peaks regularly include months outside of the selected four months used in the COSS. He said it would be arbitrary and unreasonable to use a 4CP method if there is not even a consistent set of four peaking months. He noted that Duke's production plant is also designed and planned to provide for the energy needs of its retail customers throughout the year, rather than to exclusively meet peak demand as he said Industrial Group witness Collins, OUCC witness Dr. Zarnikau, and Walmart witness Perry suggested.

Mr. Inskeep disagreed with Mr. Collins's contention that the 12CP method is not reflective of cost causation since off-peak months are not the cause of Duke's capacity requirements. Mr. Inskeep explained that off-peak months are, in fact, the direct cause of a significant portion of Duke's capacity requirements because Duke must meet MISO seasonal capacity obligations that include differentiated resource adequacy requirements for the off-peak seasons of spring and fall.

Mr. Inskeep stated Dr. Zarnikau's proposal to "skip over" peak demand usage from December 2022 and instead use the fifth-highest peaking month in the historic base year (June 2023) to arrive at a 4CP based on the peak demand in the months of June 2023, July 2023, August

2023, and September 2022 was arbitrary. He said the proposal would shift cost allocation to only considering peak usage during four summer months in the historic base year, ignoring that production plant investment and operations are caused by capacity and energy needs throughout the entire year. He said a more reasonable approach would be to adopt a cost allocation methodology that does not produce the radical year-to-year swings of the 4CP cost allocation methodology that is easily biased by one outlier month.

Mr. Inskeep cited Ms. Diaz's testimony in Cause No. 45253 as proof that the main reason Duke switched to 4CP cost allocation in its class cost of service study in its prior rate case, Cause No. 45253, is because it agreed to do so under a term from the 2005 Duke Merger Proceeding (Cause No. 42873). He stated that the 4CP usage in Cause No. 45253 was justified on the basis that Duke's monthly peak loads were consistently higher in the four summer months, which Duke's base historic year (showing December 2022 as the third-highest peaking month) demonstrates is no longer the case today.

Mr. Inskeep also argued that 4CP cost allocation methodology is inconsistent with transmission cost causation.

h. <u>Industrial Group Cross-Answering Testimony</u>. Mr. Collins responded to the Direct Testimony of OUCC witness Dr. Dismukes with respect to his recommendations on the appropriate cost of service methodology for Duke's class cost of service study and his proposed class revenue distribution. Mr. Collins opposed Dr. Dismukes' Average and Peak cost allocation method. [14] He reiterated that his contention that Duke should continue to use a 4 CP allocation method, as recommended in his direct testimony. Mr. Collins testified that Mr. Dismukes' asserted justification in support of his recommended change—that utility investments in generation are energy-related because utilities spend more capital costs in order to lower fuel costs—is the same argument that has been made by the OUCC, and subsequently rejected by this Commission, in prior Causes. Mr. Collins testified that the basic underpinnings to this argument no longer exist because gas-fired combined cycle generation constitutes both low capital costs and low fuel costs and thus, there is no longer a reason to spend additional investments on coal or nuclear generating units to reduce fuel costs. Moreover, Mr. Collins stated that while Dr. Dismukes' argument in favor of the use of the Average and Peak method assumes that utilities will invest in more expensive types of generating capacity solely because of the lower fuel costs associated with that capacity, it fails to recognize that under this assumption, base load plants may have higher capital costs than peaking units but their operating costs would be relatively lower. Mr. Collins explained that by ignoring the fuel cost differential, Dr. Dismukes' proposed approach creates a mismatch between the theory behind the Average and Peak method and its application. Mr. Collins testified that if the capital substitution theory is to be applied in determining the allocation of production plant, it would also be logical and consistent to apply the same principles to the allocation of fuel expenses.

Mr. Collins further testified that not only is he not aware of any orders issued by the IURC that would support the classification and allocation of production investment costs on an energy basis, but he stated the approach has also been consistently rejected by the Commission in past

[14] We note Dr. Dismukes referred to this method as "Average and Peak" while Mr. Collins refers to it as "Peak and Average." For consistency, will use Dr. Dismukes' designation.

decisions. Furthermore, Mr. Collins testified the Commission has historically expressed a preference not to change approved allocation methodologies unless evidence demonstrates system operating characteristics have changed materially since the last time the Commission approved a cost of service methodology. Mr. Collins asserted that Dr. Dismukes has not shown that there has been a significant change in the operational characteristics of Duke's system. Rather, Mr. Collins stated that the system continues to rely extensively on coal-fired and natural gas-fired generation while also continuing to show consistent summer peaks reflective of cost causation. Mr. Collins therefore recommended the Commission reject Mr. Dismukes' proposed shift to an energy weighted demand allocator.

Mr. Collins also responded to the Direct Testimony of CAC McCann regarding cost of service methodology and related issues. Mr. Collins stated that, similar to Dr. Dismukes, Dr. McCann recommends an energy component to the allocation of fixed production costs, despite the Commission's determination in Duke's most recent rate case that those costs were 100% demand-related and while failing to present any compelling evidence of any material change in operating circumstances that would support a dramatic shift away from the Commission's recent findings.

i. <u>Nucor Cross-Answering Testimony</u>. In cross-answering testimony, Dr. Zarnikau disagreed with the OUCC and CAC's recommendations regarding the appropriate cost of service methodology. Dr. Zarnikau reiterated his original recommendation that the 4CP method is the appropriate means to allocate the costs of generation and transmission demand costs and that production plant capacity costs should be classified as demand related costs, stating that there is no empirical support for a 12CP method. Dr. Zarnikau also opposed OUCC witness McCann's analysis regarding the CONE for separating fixed and variable costs. Dr. Zarnikau asserted that under Dr. Dismukes' CONE analysis, the portion or share classified as energy-related and demand-related could vary considerably year to year, lack stability over time, and is therefore an inappropriate approach. Dr. Zarnikau opposed OUCC witness McCann's testimony regarding classifying a share of production fixed costs as energy related. Dr. Zarnikau stated it is inconsistent to partition power plant costs without also partitioning costs not associated with the capital cost of power plants (e.g., fuel and labor) between demand and energy. Dr. Zarnikau also responded to OUCC testimony regarding the CONE for separating fixed and variable costs. Dr. Zarnikau disagreed with the OUCC's recommendation of classifying a share of production fixed costs as energy related.

j. <u>OUCC Cross-Answering Testimony</u>. In response to the Industrial Group's evidence, Dr. Dismukes testified that his analysis of Duke's system for 2019–2023 indicates that the Company's system can generally be described as exhibiting the characteristics of a 12CP system. Furthermore, he stated cost-causation is necessarily shifting toward the 12 CP methodology as electrical systems are transitioning from traditional fossil fuel driven systems to ones increasingly reliant on renewable energy. Likewise, he said the Company's proposal to change its allocation of demand-related transmission costs is consistent with MISO's approach to allocating network transmission costs.

k. <u>Duke Rebuttal</u>. On rebuttal, Ms. Diaz explained that customers use the system on a year-round basis, but the application of cost causation leads to the conclusion that fixed costs should be allocated on a demand basis. Ms. Diaz explained that the

Company's production demand methodology relies upon the premise that the purpose of the resources is for long-term planning, and not based upon the operational use of the resources as proposed by Dr. McCann. Ms. Diaz further explained that the use of the different resources, such as renewables, and their operations in any given hour, is not related to the Company's position, which is that Duke must provide adequate generating capacity to meet the demands of customers when those customers make those demands on the system. Ms. Diaz testified that the fact that resources provide an energy benefit in certain hours is secondary, as it did not cause the investment. She also explained that allocating production plant costs on both demand and energy contradicts the argument that there are peaks on the Company's electric system. She testified Industrial Group witness Collins supported the Company's position by stating that any method of cost allocation that utilizes a form of average demand or energy to allocate production and transmission plant is at odds with the dominant system peaks on its electric system and should be rejected.

Ms. Diaz testified that the Company continues to support its proposal to use the 12CP methodology. She testified that utilizing the 12CP methodology is appropriate and warranted. She testified that the Company understands the proposed change impacts rate classes differently and she identified the factors which led to Duke's proposed change.

Ms. Diaz testified that MISO establishes capacity requirements for its member utilities based on peak demand and reserve criteria and explained that the MISO requirements have changed since the Company's last rate case. Ms. Diaz further explained that MISO's new requirements move from a summer peak to four distinct seasons (summer, fall, winter, spring) for planning of generation resources and while the Company's 2021 IRP used the summer peak for capacity planning because of the rules in effect at the time, the 2024 IRP cannot. Thus, Ms. Diaz testified the Company's IRP process has shifted away from an emphasis solely on summer peaks. Ms. Diaz further testified that now, each season has a unique planning reserve margin, and the Company schedules its maintenance to accommodate each season. She testified a generation fleet is planned to meet demand year-round.

Ms. Diaz explained that by averaging the 12 monthly peaks, the 12CP method mitigates the weather effect that was observed in the highest peak more so than a 4CP method containing the highest peak. She testified that averaging 12 monthly peaks also increases the likelihood of rate stability from test period to test period. Ms. Diaz further testified that 12CP does not require complex models to weather-normalize demand prior to use in cost allocation and that constant transmission is also needed for reliability throughout the year, supporting the 12CP which uses multiple peaks. She further testified that MISO allocates network transmission charges to its load serving market participants using a 12CP allocation MISO has also studied the impact of renewable resources and concluded that the stress on the transmission system, besides the stress caused by peak demand, is impacted by the shoulder seasons of spring and fall due to renewable resources generating energy in these seasons. Ms. Diaz testified the 12CP method is frequently used in allocating costs to customers, and further testified it is reasonable and a methodology that has been approved by state commissions, as well as FERC. Ms. Diaz explained that the circumstances since Cause No. 45253 have changed and are no longer appropriate. Ms. Diaz further testified that a prior regulatory settlement supporting a 4CP methodology has lapsed with no continuing obligation. Ms. Diaz explained that Duke also considered the practical application of affordability for residential customers, while also considering the impact the 12CP methodology has on the remaining classes. She asserted that Duke's proposal is fairer and more equitable for all customer classes than the proposals set forth by Nucor, Walmart, and the Industrial Group. Ms. Diaz further explained that because FERC tests are guideposts and not steadfast rules for decision making, she did not give as much weight to the results of the tests as advocated by the intervenors. She emphasized that as discussed in her direct testimony, the Company was close to passing two of the three guidepost tests.

l. Additional Evidence Received at Hearing. Ms. Diaz testified that Duke's system must be sized for multiple points in time, and Duke must evaluate its customers' behavior at those times or seasons. She noted MISO has changed from an annual peaking point to multiple seasons, as Duke included in its IRP planning. Ms. Diaz stated the point of the MISO seasonal construct is that all the seasons are important, and all the months in each season are important.

Ms. Diaz testified that if Duke only procured enough generation capacity to meet a 4CP peak, this would not necessarily be sufficient to meet MISO's resource adequacy requirements. She stated it would not be in concert with MISO's requirements for reserves and capacity in each season. Ms. Diaz confirmed that a portion of the MISO transmission costs are allocated using 12CP, and MISO does not use a 4CP.

Ms. Diaz confirmed that the December 2022 Winter Storm Elliot was included in the historical factors the Company used in its cost-of-service study. She also confirmed a 4CP would use the data from that "extraordinary December 2022." Tr. at C-46.

m. Commission Discussion and Findings. The first issue to resolve is whether a portion of fixed production costs should be allocated based upon energy. Steel Dynamics, Nucor, and the Industrial Group agreed with the Company that no portion of fixed production costs should be allocated on the basis of energy and it should only be allocated based on demand. The OUCC and the CAC raised their arguments against classification of electric generation production plant at 100% demand in Duke's last rate case. In that Cause, the Commission found the following:

> The energy-weighted demand allocation methodologies proposed by Joint Intervenors do not recognize that production plant costs are fixed in nature and exist regardless of how much energy customers consume. Because production plant capacity is required to meet peak demand requirements, plant capacity costs are appropriately allocated to customers based on their contribution to peak demands, since there is a direct relationship to the demand that customers place on the system. Based on the evidence in this proceeding, we decline to allocate production cost based on energy consumption.

Duke Energy Indiana, LLC, Cause No. 45253 at 120 (IURC June 29, 2020).

We have never found that fixed production costs should be allocated on any basis other than demand. The OUCC and intervenors have not persuaded the Commission to change its long-standing position. We agree with Ms. Diaz that using Dr. Dismukes' and Dr. McCann's proposed allocation methods would result in higher load factor customers being negatively impacted. Adoption of the intervenors' alternative methods would discourage efficient use of the system because high load factor customers promote the efficient utilization of the system, which benefits all customers. Allocating production plant as a demand-related cost sends a cost-based pricing signal that discourages power usage at the time of the system peak demands. We therefore find that no portion of fixed production costs should be allocated on the basis of energy.

The Commission further finds that the 12CP method used for production costs and advocated by Duke is superior to the 4CP method the industrial intervenors advocated in part because the 12CP method recognizes MISO's new requirements (developed after the issuance of our Order in Duke's last base rate case) moving from a summer peak to four distinct seasons (summer, fall, winter, and spring) when generation resource planning. Duke's generation fleet is planned to meet generation year-round. We also recognize that Duke's 12CP method mitigates the weather effect(s) that had been observed in the highest peak. Methodologies that account for meeting demand year-round, as Duke's system is designed to do, have the added benefit of likely rate stability from test period to test period.

We note from Dr. Dismukes' testimony, his analysis of the Company's historic monthly system peak demands for the calendar years 2019–2023 shows the Company's system passed both the On and Off-Peak and Average to Annual Peak FERC tests each calendar year from 2019 through 2023. We believe this demonstrates that the system's failure on these tests, even marginally, for 12 months ending August 31, 2023, is likely due to the time period examined by the Company (which includes part of 2022 and 2023). Dr. Dismukes analysis also finds that the Company's system passes the final FERC test, Low to Annual Peak, in two of the prior five calendar years. Nucor is correct that expanding the timeframe for the respective tests does not equate to passing these tests. However, such a longer-term view does help place the test results in a fuller context. This is particularly true because, as we have previously found, the FERC tests are guideposts and not steadfast rules for decision making. *See NIPSCO*, Cause No. 43526 at 84 (IURC Aug. 25, 2010) ("While we are not bound to directly apply the FERC Allocation Method Tests for retail ratemaking in Indiana, we find the guidelines useful information for determining the appropriate production cost allocation methodology.")

There are numerous reasons why the 12CP methodology is appropriate now for Duke and Ms. Diaz explained those reasons thoroughly in her testimony. As the Commission stated in Cause No. 45253, operational changes, including the wholesale market and how MISO establishes capacity requirements guide how costs should be allocated. *See* Final Order in Cause No. 45253, pp. 119-120.[15] Although in Cause No. 45253 the Commission found the 4CP methodology

15 "The evidence of record reflects that significant operational changes have taken place since Duke's last rate case. The Company's last rate case filed by PSI was Cause No. 42359, which was filed at the end of 2002 and was decided by Commission Order dated May 18, 2004. While our decision in this proceeding is driven by Duke's specific service characteristics, we note that the circumstances in the wholesale market and the related impact on Duke's operation is one such change. At the time Duke received an order in its last rate case, MISO had only recently been formed and approved by FERC as an RTO. Currently, MISO establishes capacity requirements for its member utilities based on peak demand and reserve criteria. Consequently, Duke's capacity needs are now determined by its contribution to the MISO system's peak, which occurs consistently in the summer period. In addition, the bargain reached in Cause No. 42873 by the settling parties, the OUCC among them, included self-imposed constraints on this topic that we find

appropriate, using the same guiding principles to the facts of today, we now find the Company's proposed 12CP methodology to be appropriate.

Further, the Company's IRP is not controlling on this particular topic because MISO requirements have changed since the Company's IRP and since its last base rate case. The Commission finds it is reasonable to recognize that MISO now establishes capacity requirements for its member utilities based on peak demand and reserve criteria. MISO stated in its Renewable Integration Impact Assessment Summary Report – February 2021 that it is extremely important to note that grid planning is changing. MISO has studied the impact of renewable resources and has concluded that the stress on the transmission system, besides the stress caused by peak demand, is impacted by the shoulder seasons of spring and fall due to renewable resources generating energy in these seasons. This is why we give weight to the fact that MISO allocates network transmission charges to its load serving market participants using a 12CP allocation.

By averaging the 12 monthly peaks, the 12CP method mitigates the weather effect that was observed in the highest peak more so than a 4CP method containing the highest peak. Averaging 12 monthly peaks also increases the likelihood of rate stability from test period to test period. Further, 12CP does not require complex models to weather-normalize demand prior to use in cost allocation. Constant transmission is also needed for reliability throughout the year, thus supporting the 12CP methodology which uses multiple peaks. Therefore, we find that the evidence in this proceeding supports a finding that use of a 12CP methodology is reasonable, just, and supports affordability.

ii. Minimum System Study/Distribution Allocation.

a. Duke Case-in-Chief. Mr. Rimal sponsored special system studies that he conducted to (1) sub-functionalize certain distribution assets (i.e., poles and conductors) as being related either to the primary distribution system or secondary distribution system and (2) classify these assets as being either related to customer or demand. Pet. Ex. 8 at 2-8, Attachment 8-B (BR) and Attachment 8-C (BR). In particular, the results of the Minimum System Study ("MSS") are used to classify primary and secondary-voltage assets associated with FERC Accounts 364 – Poles, Towers, and Fixtures; 365 – Overhead Conductors and Devices; and 367 – Underground Conductors and Devices, as customer related. He explained that the results of his studies were used in the retail cost of service study sponsored by Company witness Ms. Diaz.

b. CAC Case-in-Chief. Dr. McCann testified that the Company's MSS confuses "minimum" with "lowest customer demand" and that the method is applied mechanically with no supporting economic analysis.

c. Industrial Group Case-in-Chief. Industrial Group witness Collins recommended that the Company use the MSS for rate setting. Mr. Collins testified that the allocation of a portion of distribution system costs as customer-related is appropriate for cost allocation. He explained that by using the Company's cost of service models (and adjusting the subsidy/excess reduction to 33%), he produced different scenarios which use the minimum system

should be given at least a measure of weight. The evidence in this proceeding does not support a finding that use of a 4CP methodology is unreasonable or unjust."

approach for both 12CP and 4CP. He endorsed the MSS with 4CP as the most accurate depiction of the cost for the Duke system.

d. <u>OUCC Case-in-Chief</u>. Dr. Dismukes recommended that the Commission reject the Company's MSS and instead classify the relevant distribution plant Accounts 364-367 as 100% demand-related. He said MSS and related zero-intercept approaches are fundamentally flawed and provide little to no value as to the just and reasonable setting of rates.

e. <u>CAC Cross-Answering Testimony</u>. Mr. Inskeep agreed with Dr. Dismukes' rationale to reject Mr. Collins' recommendation to use the minimum system method. He said adopting the minimum system method against the recommendation of Duke, CAC, and OUCC would increase the rate increase for the residential class from 18.99% to 20.53%, further exacerbating residential affordability, primarily to the benefit of high load factor ("HLF") and low-load factor ("LLF") customers. It would also have catastrophic impacts for Lighting Service customers, increasing their rate increase from 30.9% to a shocking 61.9%.

f. <u>Industrial Group Cross-Answering Testimony</u>. In his cross-answering testimony, Mr. Collins responded to Dr. Dismukes' criticism regarding the classification of certain distribution plant costs into a demand component and a customer component. Mr. Collins rejected the what he found to be Dr. Dismukes' implication that the minimum system approach is a disfavored and unsubstantiated method that is contrary to accepted practice nationally. Mr. Collins reiterated his position that NARUC recognizes a customer component as being appropriate in the classification of distribution plant and stated that he continues to recommend the use of this cost-based enhancement to Duke's cost of service study. Mr. Collins stated that while he agrees with Duke's use of a MSS to properly classify a portion of distribution costs as customer-related, this study should have also been used in the allocation of costs in FERC Accounts 364 and 368.

g. <u>OUCC Cross-Answering Testimony</u>. Dr. Dismukes responded to Mr. Collis' testimony. Here, Dr. Dismukes reiterated his direct testimony that the Commission should reject Duke's MSS based upon his earlier testimony that MSSs are incorrect from a theoretical perspective as well as from a practical perspective. He stated the Industrial Group did not provide testimony that addressed what he described as "fundamental flaws." In closing, Dr. Dismukes reiterated the recommendations he set forth in his direct testimony.

h. <u>Duke Rebuttal</u>. Mr. Rimal explained in rebuttal that not all distribution costs are solely related to the amount of peak demand. He explained that the NARUC manual, many costs analysts, and the Commission in a previous Indiana utility case have classified a portion of the distribution system costs as customer-related and that Dr. Dismukes' recommended demand allocator ignores this fact of the electric delivery system. He further argued that Dr. Dismukes and Dr. McCann are confusing the MSS with zero intercept study. He said establishing the cost of a zero-load conductor is a pre-requisite for a zero-intercept study and not a MSS. He explained that the NARUC Manual, which he relied on to conduct his studies, states that the minimum sized conductor should be the minimum sized conductor currently being installed. He further explained that generation assets are constructed to generate electricity and not distribute electricity and connect customers to the grid. Mr. Rimal testified that the distribution system is constructed to move electricity from transmission facilities to individual customers distributed geographically throughout the Company's service territory. He further testified the distribution system provides the path connecting the customers to the supply of electricity produced by generators and transmitted by the transmission system. He explained that the same is not true of the transmission grid and generation portfolio, and so Dr. McCann's claim that "[t]he same minimum system costs can be attributed to the transmission grid and generation portfolio as well, but that is not being proposed here, and for good reason." is incorrect. Pet. Ex. 34 at 9 *citing* CAC Ex. 2 at 32.

Ms. Diaz explained that in response to Dr. McCann's recommendations, Company witness Flick's rebuttal testimony explains the cost of service-based charge was merely a starting point. Ms. Diaz further explained the Company also decided not to propose customer charges that fully matched the customer charges in the MSS, effectively relying upon the Company's 12CP scenario without the MSS option as the starting point to which adjustments for rate increase percentages were applied in the rate design process.

Ms. Diaz testified she did not agree with Mr. Collins' recommendation to fully use the results of the MSS in this retail proceeding. She said that completion of this study was a step not taken in previous Duke rate cases and that Duke's objective is not to propose drastic rate increases on components of customer bills; instead, the Company has relied upon the Commission's gradualism approach across the classes, as explained in Company witness Flick's rebuttal testimony. She stated that Mr. Collins recommended the allocations occur on both a demand and customer basis and not exclusively demand as was supported in the Company's 12CP scenario (without the MSS option). She said while Mr. Collins' recommendation regarding distribution plant allocation for Accounts 364 through 368 is valid, rate design was not able to rely exclusively on the MSS's results and proposed gradualism in setting of the connection charges.

i. <u>Commission Discussion and Findings</u>. We find the arguments presented by the intervening parties and the OUCC to be arguments against the fundamental principles of a MSS, rather than concerns unique to the Cause at hand. We have previously held that the use of a MSS is appropriate to allocate distribution costs. *See., e.g., S. Ind. Gas and Elec. Co.*, Cause No. 43839 (IURC Apr. 27, 2011) and *Indianapolis Power & Light Company*, Cause No. 44576 (IURC Mar. 16, 2016). The Commission agrees with Duke's methodology underlying the MSS and Duke's objective of not proposing drastic rate increases on components of customer bills. We approve the MSS and the more measured customer charges recommended by Mr. Flick. This aligns with the Commission's gradualism approach across the classes, as explained in Company witness Flick's rebuttal testimony, which we will more thoroughly address below during our discussion of the customer charge.

iii. <u>Revenue Allocation</u>.

a. <u>Duke Case-in-Chief</u>. Ms. Diaz discussed the cost allocation methodologies and techniques employed by the Company within the COSS which allocates most of the Company's proposed revenue requirement to rate classes. She further supported the Company's subsidy/excess adjustment. She explained that the proposed rates are based on a subsidy/excess reduction of 5%, resulting in a proposed residential increase of 19%. Ms. Diaz's Confidential Attachment 6-G (MTD) provided further details on allocations including the reallocation for the subsidy/excess.

b. **OUCC Case-in-Chief.** Dr. Dismukes asserted that Duke's proposed revenue distributions suffer from two major deficiencies: (1) Duke's proposal is based on the results of a faulty COSS that overstates the extent of any current subsidy from high-load factor industrial customers to low-load factor residential and small commercial customers and (2) the Company's proposal to use the full results of its COSS for most customer classes is inconsistent with rate gradualism and could also negatively impact energy affordability, particularly for the Company's low- and middle-income customers. He recommended the Commission use his proposed class COSS for revenue distribution across customer classes, which would result in an 18% increase for residential customers. Dr. Dismukes recommended that in the event the Company's COSS is used, the Commission should adopt a more reasonable revenue distribution allocation method that limits the rate increase to any single customer class to no more than 1.15 times the overall system average increase. He recommended this limitation to mitigate rate shock, especially among low-income households and small businesses already experiencing financial constraints resulting from lingering inflationary pressures. Dr. Dismukes opined that using the Company's full results from the COSS for most classes is inconsistent with gradualism and could negatively impact affordability.

c. **Industrial Group Case-in-Chief.** Mr. Collins argued that Duke's revenue allocation is out of balance and that Duke is proposing to rectify this issue. However, he testified that Duke's proposed method of distributing its requested rate increase to classes reduces existing interclass subsidies by only 5% and results in rates that continue to contain massive subsides that are not reflective of cost causation. He explained that the Company's tracking mechanisms may have caused subsidies in its current rates, and that by changing to a 12CP, the Company is not reporting the full amount of subsidies. Mr. Collins notes that the Company's subsidy reduction in its direct testimony is less than the final subsidy reduction approved in Cause No. 45253, that the subsidy/excess levels have increased from the previous case for residential and HLF classes and argues that HLF rates should be reduced due to the current HLF rate of return exceeding the Company's requested rate of return. He proposes an alternative subsidy/excess reduction of 33% and produces various scenarios with his preferred scenario of 4CP with 33% subsidy/excess reduction and minimum system.

d. **Nucor Case-in-Chief.** Dr. Zarnikau testified that based upon the Company's proposed cost of service methodology, Duke's proposed rate increase for Nucor is excessive and violates the "no more than 20% per class" constraint that Duke applied to other rate classes, noting that the percentage increase for Nucor's firm service is the highest percentage increase in the Company's COSS. Nucor Exhibit 1 at 5 and 18. Dr. Zarnikau also stated that gradualism adjustments can be applied post-cost allocation. He recommended the Commission cap the rate increase for any retail customer class or special contract at 20%. He asserted that if, after Duke's revenue requirements are determined, the increase to a retail customer class or special contract exceeds 20%, then the excess revenues above 20% should be treated in the same manner as Duke proposes to handle revenues from lighting classes in excess of a 30% cap in the increase.

e. **<u>RRPOA Case-in-Chief</u>.** Mr. Hildenbrand explained that River Ridge is a reuse authority for former federal military base property that was established in 1998 by ordinance adopted by the Board of Clark County Commissioners in accordance with Indiana Code ch. 36-7-30. He testified that River Ridge is located on approximately 6,000 acres along the Ohio River in Clark County, Indiana, and was established to replace lost economic revenue previously generated by the now-shuttered Indiana Army Ammunition Plant. Mr. Hildenbrand stated that of the 80 businesses presently sited within River Ridge, approximately 61 property owners are members of the RRPOA, and all the businesses are customers of Duke.

Mr. Hildenbrand stated that RRPOA requests that if the Commission grants a rate increase that it consider the affordability of the increase and the ability of customers to pay for the increase and require that any increases be phased in so that customers pay no more than an additional 5% per year. Mr. Hildenbrand testified that such a phase in will help protect RRPOA's members from rate shock that could harm their businesses and result in job cuts.

f. **<u>Walmart Case-in-Chief</u>.** Ms. Perry recommended that if the revenue requirement is reduced by the Commission, the Commission should apply 50% of the revenue reduction to the classes paying more than their cost-based levels with the caveat that a subsidizing class should not move to a subsidized position, and the remaining 50% should be applied evenly to mitigate the proposed increases for all rate classes on an equal percentage basis. Ms. Perry stated the Company did not provide details on how it plans to align classes more closely with cost-based levels aside from mentioning the gradualism concept.

g. **<u>CAC Cross-Answering Testimony</u>.** Mr. Inskeep asserted that the cost allocation proposals of witnesses Collins, Zarnikau, and Perry would shift hundreds of millions of dollars in costs caused by large non-residential customers onto other customer classes, such as residential customers. He asserted that under Mr. Collins' cost allocation recommendation (which uses 4CP for production and transmission, applies a MSS, and applies a 33% "subsidy reduction"), the residential class rate increase would increase from 18.99% to 26.63%, an increase of more than 40% as compared to Duke's case-in-chief. The proportion of the overall revenue requirement increase allocated to the residential class would increase from 49.5% under Duke's case-in-chief to 69.5% under IG's proposal. Meanwhile, industrial customers would receive windfall rate subsidies. He stated the annual revenues and net profits of Walmart and three Industrial Group members, in support of his contention that such entities are more capable of paying their share of electricity costs than residential customers. Mr. Inskeep recommended the Commission adopt Dr. McCann's cost allocation recommendations. He also recommended the Commission disregard Nucor's claims about the impact of the proposed rate increase.

h. **<u>Industrial Group Cross-Answering Testimony</u>.** In cross-answering testimony, Mr. Collins testified that Dr. Dismukes' suggestion that no class receive an increase more than 1.15 times the system average is arbitrary and an impediment to reducing current subsidization in rates. Mr. Collins further explained that the narrow band of tolerance proposed by Dr. Dismukes is tantamount to advocating for an across-the-board increase near system average for all classes and disregards the cost of service analysis resulting in harm to large industrial customers. Mr. Collins recommended the Commission reject the 1.15% constraint proposed by Dr. Dismukes.

i. <u>OUCC Cross-Answering Testimony</u>. Dr Dismukes recommended that that the Industrial Group's recommended 33% subsidy reduction should be rejected because it is based upon a faulty COSS and is inconsistent with rate gradualism, impacting affordability.

j. <u>Duke Rebuttal</u>. Ms. Diaz testified that because Dr. McCann proposed different allocation to the classes for production demand and certain rider allocations, he presented a revised allocation of operating revenue and resultant rate increases which lowers residential and commercial rate increases while increasing high load factor customers' rate increases.

Further, Ms. Diaz testified that because Mr. Collins endorsed allocations to the classes by using a 33% subsidy/excess reduction, 4CP, and minimum system, he presented a revised allocation of operating revenue and resultant rate increases which notably raise residential and commercial revenues increases while lowering industrial class revenue.

Ms. Diaz testified that applying a factor of 1.15 times the system average as proposed by Dr. Dismukes is premature and increases socialization of the results without cost causation. The Commission in Cause No. 45253 applied a higher, reasonable 1.25% factor to the classes relative to the system average increase. She said Duke did not use the full results of the cost of service study as evidenced by the downstream adjustments made by rate design but stands that the cost of service study provided to rate design is valid and reasonable.

In response to Dr. Zarnikau's proposal, Ms. Diaz said there is no reason to cap the rate increase at 20% and spread the excesses across the classes. Ms. Diaz explained that further changes to revenue allocations are dependent upon the amount of revenue reduction that may be ordered, and the classes impacted by the proposed change, which are unknown at this time. She testified that any rate increases for Nucor should be based upon the entire contract as evidenced by the bill impact calculations performed by rate design and not the COSS. Ms. Diaz further testified that while additional post-allocation adjustments can be made, further adjustments should be limited and provide reasonable results.

In response to Ms. Perry's proposal on the administration of potential revenue requirement reductions, Ms. Diaz testified that the reductions could occur in any of the components of the case and to be accurate, the reduction would be mapped at the regulatory account level and would follow the cost of service methods for functionalization, classification, and allocation to calculate the updated net operating income at the class level. Ms. Diaz explained as the potential reductions would be tied to specific changes in assets and expenses, it is less accurate to socialize the reductions as recommended by Ms. Perry. She testified aligning rates perfectly with cost-based levels cannot occur with a single retail rate case but will continue to evolve over time.

Ms. Diaz further testified that applying a factor of 1.15 times the system average as proposed by Dr. Dismukes is premature and increases socialization of the results without cost causation. She explained that in Cause No. 45253, the Commission applied a higher, reasonable 1.25% factor to the classes relative to the system average increase. She testified it is the Company's goal to reflect the appropriate costs of service to the classes, while utilizing the established practice of subsidy/excess to ensure rates are reasonable and fair across all the classes.

k. Additional Evidence Received at Hearing. Ms. Diaz testified that with respect to subsidies, each class stands on its own and there are different drivers. When asked about the long-term effects of subsidy reduction from a rate case, she stated there could be different impacts from the subsidy or excess reduction, requiring an assessment of how much of a reduction can be made. She confirmed variables can change between rate cases, where the results are moving around.

l. Commission Discussion and Findings. Regarding the issues of subsidy and excess, as Ms. Diaz explained on rebuttal, the needs of all the Company's retail classes were considered in assessing the percentage of retail subsidy/excess reduction to apply in order to yield a fair increase across all retail classes. We agree that adopting Mr. Collins' proposals would result in rate shock. As Ms. Diaz explains, Mr. Collins' preferred scenario proposes overall increases to the residential class of nearly 27%. The Commission declines to approve reducing HLF rates as proposed in Mr. Collins' scenarios because of the rate shock consequences to the other rate classes.

Guided by the concept of gradualism, the Company has proposed a method of distributing the rate increase approved herein in a manner to reduce current interclass subsidies by 5% based on a desire to limit any class specific rate increase to 20%. However, because the authorized revenue increase approved in this Order is not the same as that used by the Company to develop the proposed 5% subsidy reduction, we find it is reasonable to direct a different reduction that still upholds the Company's goals. This balancing between the Company's goals and gradualism provides an appropriate application of the affordability prong of the Five Pillars. Accordingly, we find that a 25% subsidy reduction, constrained such that no specific rate class experiences an increase that is more than 25% higher than the overall increase, is reasonable and shall be reflected in compliance filings submitted in this proceeding.

B. Rate Design.

i. Time of Use ("TOU") Rates.

a. Duke Case-in-Chief. In his direct testimony, Mr. Flick explained that the Company is proposing new TOU rates for Rates RS, CS, LLF, and HLF. He testified the Company is also proposing a new non-TOU LLF Secondary rate. Mr. Flick described the basis and rationale for the new TOU periods and demand charge structures, as well as the benefits of the new and redesigned tariffs. Mr. Flick explained that the new RS, CS, and LLF/HLF TOU rates contain a customer charge, time-varying energy charges, and a reactive power charge. He noted the new HLF/LLF TOU rate differs in that it includes a new three-part demand charge.

He testified that generally all TOU rates seek to align price signals to the cost differences that exist across time (days, seasons, hours) for the electrical grid. Mr. Flick said grid operations require that supply match demand at any given point in time; thus, supply resources are called upon based on the level of system demand, which can vary greatly across days and seasons.

Increasingly, intermittent and non-dispatchable supply resources (e.g., wind and solar) are changing the supply/demand relationship, calling for changes in operational capabilities for the other supply resources, but also creating greater opportunities for price responsive demand. He stated the following perspective and goals were considered in crafting the new TOU periods: (1) better reflection of cost causation and the growing impact of renewable generation; (2) accommodating the changing consumption patterns caused by distributed energy technologies such as EV charging, energy storage, rooftop solar and other distributed energy technologies; (3) Facilitating customer modification of energy consumption patterns to create bill savings; and (4) customer experience (e.g. reduced need to modify TOU periods).

He then explained that the Company proposes to refresh all its previously defined TOU periods as follows: On-peak, Non-Winter – 5:00 p.m. to 9:00 p.m. On-peak, Winter – 6:00 a.m. to 8:00 a.m. and 5:00 p.m. to 9:00 p.m. On-peak periods do not apply to weekends and designated holidays. Discount – 12:00 a.m. to 4:00 a.m., year-round. Off-peak – All other hours not designated On-peak or Discount. Mr. Flick explained that Non-Winter months are Mid-March through October and winter months are November through Mid-March, and further explained that the Company is also proposing to shift tariff TOU rate administration from Eastern Standard Time to Daylight Savings Time to reflect Indiana's use of daylight savings time. He described the basis for the proposed TOU changes, the company's approach to designing the new TOU periods, and how the company determined the duration and pricing. Finally, he testified that the revised TOU periods that the Company is proposing in this case were derived from the Company's cost duration model.

b. **<u>CAC Case-in-Chief</u>.** Mr. Inskeep recommended the Commission modify the Company's peak period times to better align price signals with current and near-term grid conditions. Mr. Inskeep testified that the Company's proposed peak periods is not consistent with its underlying analyses. He said the Commission should modify the year-round time-of-use rate peak window of 5:00 p.m. to 9:00 p.m. as proposed by Duke to 4:00 p.m. to 8:00 p.m., which is a more accurate peak period and is more consistent with gradualism when compared to the Company's current peak period.

c. **<u>Industrial Group Case-in-Chief</u>.** Mr. Collins recommended that the implementation of Duke's proposal for revised TOU rates should be postponed until customer understanding, rate impact, and accurate pricing, without significant subsidy/excess levels, is established. He recommended that affected customers should retain the option of continuing under existing TOU rates.

d. **<u>Duke Rebuttal Case-in-Chief</u>.** Mr. Flick testified that the price signals inherent in the Company's existing TOU rates provide suboptimal price signals to participants. In response to CAC witness Inskeep, he explained that the Company's proposed TOU periods give proper balance to historic consumption patterns and anticipated consumption patterns over the coming years. Mr. Flick testified that responsiveness to such price signals should influence capacity investment decisions of long-lived assets. Mr. Flick further testified the Company prefers TOU period stability to enable customers to confidently invest in and manage consumption controls and practices without concerns that periods might move around year-to-year, making savings elusive. He explained that witness Inskeep's proposal of 4:00 p.m. to 8:00 p.m. for the on-peak period instead of the Company's proposed 5:00 p.m. to 9:00 p.m. window ignores the

Company's observation that net load observed at 9:00 p.m. in the model is higher than the net load at 4:00 p.m. He testified the Company expects this difference to persist and amplify in the future as solar penetration increases within Duke's service territory, and, as such, the periods recommended by the Company should be approved by the Commission.

e. Commission Discussion and Findings. We agree with Mr. Flick that Mr. Collins' proposal would merely prolong implementation of more accurate price signals that better reflect the actual cost of providing service to TOU rate participants. Preserving rates that send suboptimal or incorrect price signals to customers can raise system costs for all customers, to the extent customers respond to or modify behaviors in response to the historic rate designs. We decline to adopt Mr. Inskeep's recommendations as we believe Duke has taken a reasonable approach to its TOU periods. Therefore, Duke's new TOU rates for Rates RS, CS, LLF, and HLF and the new non-TOU LLF Secondary rate are approved as proposed.

ii. Customer/Connection Charges.

a. Duke Case-in-Chief. In his direct testimony, Mr. Flick explained that the Company is proposing an increase in the customer charge for residential rates from $10.54 to $13.70. He testified that the requested increase improves pricing and cost of service alignment across the residential class and the proposal is also supported by the MSS. Mr. Flick testified that the study's results show that the costs attributable to the addition of a residential customer are much higher than the customer charge requested in this case, $31.49 versus $13.70, respectively, and he presented Attachment 7-F (RAF) to Pet. Exhibit 7 for more details. Mr. Flick explained that the incremental amounts collected via customer charges would be offset proportionally by decreases in energy rates/revenue. He testified that the customer charge increase and energy rates have an inverse relationship in this rate's design. He also noted that further "flattening" or decreasing of the ratio of pricing differences between energy rate blocks is not being pursued in this case. Mr. Flick also described other customer/connection charge changes, including the customer charge increase for the CS rate structure.

b. CAC Case-in-Chief. CAC witness Dr. McCann testified that the Company's proposed increase to its residential customer charge is contradicted by its own COSS and thus should be reduced to $10.05. He asserted that Company witness Flick attempted to justify the increase in the residential customer charge with a hypothetical "minimum system" study. He states that the Company's MSS confuses "minimum" with "lowest customer demand" and that the method is applied mechanically with no supporting economic analysis. He also noted that the Company has not proposed a similar charge on large customers based on a minimum system method even though such customers have much larger dedicated utility resources.

c. OUCC Case-in-Chief. OUCC witness Dr. Dismukes recommended the Commission reject the Company's proposed customer charge increases for residential and commercial customers. He testified that the proposed increases are not needed and are not consistent with the public policy goals of promoting energy efficiency and affordability. He further testified that increasing fixed customer charges will burden low-use and low-income customers with a greater than system average percent rate increase. Dr. Dismukes also offered the results of his customer charge peer survey as Attachment DED-12 to Public Exhibit No. 11. He testified this analysis demonstrates the Company's current residential customer charge of $10.54 per month is below the average residential customer charge of $11.78 for other regional utilities. However, he further testified the Company's proposed increase to a $13.70 monthly residential customer charge is above the peer group average of $11.78, or 16.3% higher.

d. **Duke Rebuttal.** In response to Dr. Dismukes' survey results, Mr. Flick explained that if there should be any comparison to peers, the most pertinent comparison is to other Indiana investor-owned electric utilities. He testified he does not believe Ameren Illinois or Commonwealth Edison's numbers reflect the monthly meter charge that would be applicable. In support, he asserted the survey excludes some regional utilities with higher customer charges, such as Kentucky Power's $20 customer charge and Upper Peninsula Power Company's $15 customer charge. He concluded that the survey results have limited value in gauging what customer charge should be approved in this proceeding.

In response to Dr. McCann's suggestions, Mr. Flick explained that the minimum system methodology is not random and produces a definitive target for setting a customer charge on the basis of cost causation. He further reiterated that the Company filed MSS evidence in this proceeding to support its request for a customer charge increase.

e. **Commission Discussion and Findings.** We already addressed the MSS above and will not repeat a discussion here besides to acknowledge that the proposed customer charge is not at the level supported by the MSS. Mr. Flick explained that the Company offered MSS results into evidence in this case that support a $31.49 residential customer charge and he stated the Company agrees with the philosophical concepts underpinning the MSS, but also holds deference for gradualism. The OUCC and CAC oppose Duke's customer charge claiming it is not based on cost to serve, will send inefficient price signals, and will burden low-use and low-income customers with a greater than system average percent rate increase. Initially, we note Duke has not proposed straight fixed variable rates. In *Indianapolis Power & Light Co*, Cause No. 44576 at 72 (IURC 3/16/2016), the Commission approved an increase to IPL's customer charge and continuation of a declining-block rate structure, finding IPL's increased customer charge was "demonstrably short of [straight fixed variable] rates." The evidence does not show the customer charge, as designed, reaches the level of full distribution system fixed cost recovery. Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided.

Ultimately, based on the evidence, we find that Duke's proposal is consistent with the results of the COSS and the resulting monthly customer charge satisfies the guiding principles of cost causation, revenue stability, efficiency of use, gradualism, avoidance of discrimination, simplicity and feasibility, and affordability. The Commission has previously indicated a preference for gradual changes in rate structure. *See Indiana Michigan Power Company*, Cause No. 45235, (IURC 3/11/2020). We therefore approve Duke's requested customer/connection charge.

iii. **<u>Declining Energy Block Rates</u>.**

a. <u>Duke Case-in-Chief</u>. Mr. Flick indicates that Duke planned to continue using a declining block rate for residential customers. He explained that the utility's approach in designing this rate was very similar to the approach Duke used in its last base rate case.

b. <u>CAC Case-in-Chief</u>. Dr. McCann testified that the Company's declining block rates for residential customers are outdated and create perverse incentives that drive up customer bills. He stated declining block rates discourage energy conservation and deprive low use and low-income customers of an opportunity to reduce their utility bills. He opined that Duke has presented no evidence, either in its COSS or elsewhere, that justifies continued use of this rate structure. He also stated declining block rates work against the collective interests of all ratepayers by increasing the market price of power and increasing the need for capital investments. He testified the Commission should order Duke to offer only single-tier flat rates for now until a study can be conducted on a rational means for setting a two-tier increasing block rate.

c. <u>Duke Rebuttal</u>. In response to Dr. McCann, Mr. Flick explained that ordering a single energy rate in its rate designs until a 2-tier energy rate study can be completed would create administrative burden without a reasonable expectation that the result would improve pricing and cost causation alignment. He explained that, as in *Indianapolis Power and Light Company*, Cause Nos. 44576 and 44602 at 71-72 (IURC 3/16/2016), there is no evidence that would lead one to conclude that eliminating the declining block structure would benefit customers with lower incomes. He further explained that the cost curve for residential customers presented in his testimony has an initially steep declining slope and from a quantitative perspective, declining block energy rates, as well as higher customer charges, are pricing tools that could improve the Company's ability to align pricing with the costs of providing service.

d. <u>Commission Discussion and Findings</u>. Based on the evidence, it appears that Duke's plan could improve the Company's ability to align pricing with the costs of providing service. We note that this plan is consistent with what we authorized in Duke's last rate case. We further find Duke's proposed structure does not violate principles of gradualism, and when considered in the context of the entire customer bill and not as discrete charges within the bill, it is reasonable. Further, Mr. McCann did not provide compelling evidence that would lead us to direct Duke to vary from the declining block rate design currently in place. In Duke's previous rate case, the Commission approved the continuation of the declining block rate structure and there has been no evidence-based justification to warrant a change in the current Cause. Further, as Mr. Flick cited and as the Commission pointed out in the 45253 Order, replacement of declining block rates with increasing block rates, as was suggested by Mr. McCann, could cause harm to customers that use above an average amount of energy. Consequently, we approve Duke's plan and we reject the CAC's invitation to eliminate declining block energy rates.

iv. **HLF and LLF Demand Rates.**

a. **Duke Case-in-Chief.** Mr. Flick explained that Duke's current rate structure (declining energy blocks within a tiered, hours use construct) has produced unintended consequences; namely, typically large, high load factor characteristic 1 secondary service customers have found savings through participating on this low load factor rate. As such, he explained that Duke proposed a new demand charge structure for LLF Secondary Service and a new Secondary HLF rate.

He said Duke proposed to close its existing LLF Secondary rate to new participants and to offer a new rate with a new structure as its successor. Mr. Flick said that to allow for current rate participants to plan and prepare for future rate transition, the Company proposed the rate be terminated the later of five years after new rates are effective, or through the Company's next rate case, with existing net-metering customers allowed to remain.

Mr. Flick also described Duke's proposed LLF Secondary rate. He explained that the new rate does not have a declining block energy rate or hours use construct and is proposed to be composed of: (1) connection charge, (2) demand charge, (3) energy rate, and (4) a reactive power charge. In short, the new LLF Secondary rate was structured much like the other legacy Low Load Factor rates under the existing tariff. He said Duke will communicate the proposed charges through a bill insert.

b. **Kroger Case-in-Chief.** Mr. Bieber stated that Duke's proposed HLF Secondary and New LLF Secondary rate design understates the demand-related charges relative to the underlying costs while overstating the energy-related revenues. Specifically, he said the Company's proposed HLF Secondary rate design would only recover 75.7% of fixed demand related costs through $/kW demand charges while recovering 156.3% of variable energy related costs through $/kWh energy charges. He recommended changes to the Company's proposed HLF Secondary rate design that he said would make progress towards aligning the rate design with the underlying costs while also employing gradualism and mitigating the intra-class rate impacts that would result from a more significant movement towards cost-based rates at this time. Mr. Bieber also criticized the Company's new LLF secondary rate design as not aligning with cost causation.

c. **Duke Rebuttal.** Mr. Flick said the Company is concerned that Mr. Bieber's suggestion could adversely and materially impact some customers and thus the Company prefers a more gradual approach to increasing the percentage of fixed costs recovery through demand charges in alignment with cost causation. He explained that the Company's power rates are particularly sensitive to changes such as those Mr. Bieber is proposing. Mr. Flick testified he believes the Company's proposed design is a reasonable choice. He explained that the new LLF Secondary rate, which adds a demand charge to a rate that did not have one before, improves pricing alignment with cost causation.

d. **Commission Discussion and Findings.** We find it is appropriate for Duke to propose demand rates that improve pricing alignment with cost causation but also take a gradual approach. The evidence presented by Mr. Flick shows the Company's proposal aligns with these principals. Further, Mr. Flick presented graphics that show the new LLF Secondary rate design better mirrors the unit cost curve versus the old LLF Secondary's rate. Given the evidence of record, the Commission rejects Mr. Bieber's recommendations regarding demand rates and approve Duke's proposal because we find it more closely aligns with the principles of improving price alignment with cost causation while taking a rate gradualism approach.

v. Multi-Family Customer Rate.

a. CAC Case-in-Chief. CAC witness Inskeep recommended the Commission direct Duke to perform a study so that the Company may begin taking steps that would enable the evaluation and creation of a multi-family rate class and rate schedule in the future. He noted three investor-owned electric utilities outside of Indiana which offer a multi-family rate and that such rates aim to better align residential rates with cost causation and economically efficient rates. Mr. Inskeep testified that establishing a multi-family rate class is sound policy, in addition to being sound ratemaking and adhering to cost of service principles. He testified that such a rate also addresses affordability and equity issues as economically challenged customers are more likely to be renters and thus may be paying above their cost of service relative to single-family ratepayers. Lastly, Mr. Inskeep asserted that creating a multi-family rate class would not decrease revenues for Duke as eligible residential customers would be separated into a multi-family rate class in a future COSS.

b. Duke Rebuttal. On rebuttal, Mr. Flick testified that the Company believes it should largely retain the autonomy to prioritize the pursuit of new programs, services and rates which take dedication of finite resources. He stated the Company offered an additional pricing choice to its entire residential rate class in this proceeding with its new, proposed residential TOU rate. If approved, he said that rate may prove attractive to some in the segment of residential customers witness Inskeep is targeting with his proposal. In response to Mr. Inskeep's reference to certain utilities having a multi-family tariff, Mr. Flick noted that there may be significant differences in each of those utilities' service territories. Mr. Flick recommended the Commission deny Mr. Inskeep's proposal for the commencement of such a study.

c. Commission Discussion and Findings. We find insufficient evidence for us to compel Duke to undertake the study proposed by Mr. Inskeep. We encourage Duke to consider all its options, including a multi-family rate, when considering its future rate design.

vi. Excess Distributed Generation. The Company proposed no adjustments to its excess distributed generation tariff in this proceeding. CAC witness Inskeep recommended the Commission order Duke to convene a distributed energy resource collaborative to develop a new alternative regulatory plan that could be filed for approval with the Commission that would establish an alternative distributed generation tariff. In rebuttal, Mr. Flick asserted that issues surrounding excess distributed generation legislation have been extensively litigated to conclusion. We find the record lacks sufficient evidence to support Mr. Inskeep's recommendation and decline to require Duke to take any action.

C. **Revenue Rate Migration Adjustment.**

i. Duke Case-in-Chief. Mr. Flick noted Duke's rates have been revised to produce the target class and total revenue requirements being sought in this proceeding. He said the Company is also proposing a number of rate design changes to protect customers from cross-subsidization, send price signals that encourage system beneficial consumption, and generally modernize the Company's pricing structure, including Duke's new TOU rates. He also noted Duke's proposal to increase customer charges and to offer a new, redesigned LLF Secondary service rates.

Mr. Flick testified that any time rates are redesigned or modified to produce a different revenue requirement, or new pricing choices are added, there is a potential that certain customers will benefit economically under a different rate schedule when compared to the schedule under which customer is billed currently. He explained Duke designed a proposed migration adjustment to account for revenue erosion associated with customers switching from one rate to another to save money after rates are reset in this rate case. He said that through the requested migration, Duke seeks to design rates that will ultimately recover the approved revenue requirement. Without the migration adjustment, he said the approved rates would not recover the full costs of service. Mr. Flick testified that historically, the Company has been able to reflect the effects of customer migrations in the development of its rates, a practice that is reasonable to continue, particularly considering the wider customer availability of rate choices the Company has proposed in this case. Providing customers rate choices that allow for selection of rates most favorable to their service characteristics is increasingly desired by Duke's customers. Failure to recognize the financial implications of customers electing a cheaper (better) rate in the ratemaking process would unduly penalize a utility for offering valued rate choices to its customers. He stated that Duke used conservative approaches in developing the migration amount requested.

Mr. Flick described the criteria which Duke used to develop its migration adjustment. In addition to certain minimum monetary savings thresholds, he noted the criteria included a requirement that residential and commercial customers have an opportunity to save 10% of their annual bills and HLF and LLF Primary and Primary Direct customers, as well as HLF and LLF Transmission Service customers had a 5% savings threshold. He noted Duke considered the results of a unit cost study in designing the proposed rates and that setting rates that are aligned with unit cost minimizes interclass cross-subsidization and signals to customers the true cost impact of their usage.

He explained that the results of the Company's migration analysis are shown on Attachment 7-G (RAF) and Attachment 7-H (RAF) to Pet. Exhibit 7. He said the Company calculated $32.5 million of potential customer savings from rate migration. Mr. Flick testified the Company's experience suggests that even with the awareness of a bill savings opportunity some customers will not change rates. Accordingly, Mr. Flick explained that the Company has reduced the total migration amount by 50% to $16.3 million and used minimum savings thresholds in calculating the $16.3 million migration amount sought for recovery. The $16.3 million in expected revenue decreased due to anticipated rate migration from rates RS, CS, LLF, and HLF has been allocated to these rates, respectively.

ii. <u>OUCC and Intervenors</u>. The OUCC, CAC, Industrial Group, and Kroger presented evidence suggesting that the Company overestimated the amount of revenue reduction (migration related lost revenue) associated with anticipated rate switching and/or proposed computational changes to the calculation.

a. <u>OUCC Case-in-Chief</u>. Mr. Hanks stated that given the low interest in Duke's prior dynamic pricing pilot program (Flex Savings Option Pilot), he said it is premature and speculative in this Cause to charge all customers because some may end up saving money on the new rate. He stated that not all customers who switch to the TOU will save money. Mr. Hanks testified that Duke failed to consider the increased revenue from ratepayers who switch to TOU and pay more due to use during peak times or those who use more energy at discounted times due to the discount, as occurred in the Flex Savings Option Pilot.

Mr. Hanks stated that if the proposed migration adjustment amount is approved and fewer customers switch to TOU rates than projected, Duke will receive revenue from the migration adjustment and higher revenue amounts from the customers who are projected to switch but do not.

OUCC witness Dr. Dismukes testified that Duke did not provide evidence to support its assumption that 50% of its customers will switch to a TOU rate. He stated research does not support a 50% adoption rate, citing a 2019 study that found 60% of investor-owned utilities offering TOU rates had enrollment rates of less than one percent, as well as a 2018 study that found only four percent of all residential customers in the United States took service under a TOU rate. Dr. Dismukes recommended the proposed migration adjustment amount be reduced to one-third of Duke's proposed amount, which corresponds to the assumption that only 16.5% of residential and small commercial customers will adopt TOU rates. He stated this adoption rate is more realistic based on historic experience.

b. <u>CAC Case-in-Chief</u>. Mr. Inskeep recommended the Commission deny the Company's request to recover lost revenues associated with customer migration to TOU rates, particularly for the residential customer class, because he asserted Duke's estimated rate impact is based on an unreasonable methodology and fails to account for cost savings. He noted that Duke's assumption that around 70,000 residential customers will switch to the new TOU offering stands in contrast to a recent rate design pilot in which less than 700 customers chose to subscribe to time-varying price options. He also noted that some migrating customers could end up paying more on TOU rates than on the traditional rate schedule. Mr. Inskeep recommended denial of the migration adjustment; he also testified that to the extent the Commission approves the Company's request for lost revenues against CAC's recommendations, the Commission should require the Company to track both actual lost revenues and cost savings and defer the net balance for possible future recovery in a subsequent rate case rather than include estimated future lost revenues in this case. Similarly, CAC witness Dr. McCann also noted that Duke is failing to account for behavioral changes that will create cost savings, and he also suggested migration related to lost revenues should be determined after migration has actually occurred. Using his methodology, Mr. McCann testified the Company's revenue requirement should be reduced by $16.25 million and the amount redistributed to the rate classes in proportion to projected TOU participation.

c. Industrial Group Case-in-Chief. Mr. Gorman stated the migration amount is not fixed, known or measurable and is at odds with Duke's recent experience. He recommended that rate migration adjustment of $16.3 million be rejected in its entirety.

d. Kroger Case-in-Chief. Kroger argued that Mr. Flick's analysis merely quantifies the maximum amount of potential revenue erosion. Kroger did not address the likely level of customer migration. Kroger argued that Duke did not provide an evidentiary foundation for its assumption that 50% of customers will proactively notify the Company that they would like to change tariff schedules. Kroger noted that Duke was asked in discovery and at hearing to provide such evidence and declined to do so. Kroger stated that the only evidence in this proceeding that provides an example of voluntary switching behavior was submitted by the OUCC through its witness John Hanks relating to the actual switching rates associated with Duke's Flex Savings Option Pilot program, which shows a switching rate of less than 1%. Further, Kroger witness Bieber suggested lost revenue from rate migration should be assigned to the rate class migrating customers are moving to versus from. He recommended that the Commission reject the Company's proposal to assign the $2.4 million HLF Secondary to New LLF Secondary portion of the migration adjustment to HLF Secondary.

e. Duke Rebuttal. In response to OUCC witness Hanks, Mr. Flick stated that drawing correlations from the pilot results to potential outcomes attributable to the new TOU rates is improper, especially given the improvements included in the proposed offerings. He explained Duke previously offered a suite of dynamic pricing pilot rates with capped participation. The pilot rates had more complex rate designs compared to the more traditionally structured TOU rates being proposed in the current proceeding. The pilot rates placed a higher burden on participants to track the more frequent pricing changes to maximize their value.

Mr. Flick summarized the company's computation of the requested migration amount. He explained that at the foundation of the computation is near-population level customer data for each rate class. Mr. Flick explained the Company used that data to calculate what each customer's bill would be under all eligible rate alternatives and this identifies the "best," or least expensive, rate for each customer. Mr. Flick further explained that if a customer's existing rate is the least expensive option, the presumption is they will stay on their existing rate and not migrate and, among the subset of customers that could save money on another rate, the rate providing the most savings is deemed to be the rate customers would migrate to. Mr. Flick testified the cumulative amount of customer savings is totaled by rate and then filtered by savings thresholds. He explained that while residential customers saving 5-10% may also migrate and receive lower bills, the Company excluded those savings from its rate migration recovery request. Mr. Flick further explained that after these thresholds were applied, the amount of bill savings is calculated by rate. He testified only 50% of the savings, or from the Company's perspective, lost revenue, was proposed for recovery in this proceeding. Mr. Flick testified that the Company believes its calculation is not only real (as it is derived from actual, individual customer bill analysis), but also conservative in that many potential savers are not assumed to ultimately migrate. Mr. Flick further testified that savings derived from potential behavioral changes in response to new price signals were excluded from the rate migration amount the Company proposed. He explained that such changes would only occur after a customer switches tariffs and begins receiving new price signals.

Mr. Flick testified that ultimately such behavioral changes could further reduce customer bills and yield system benefits by reducing long-term investment needs.

Regarding CAC witness McCann's suggestions, Mr. Flick explained that calculating migration lost revenue after the fact adds administrative burden to all parties involved. He testified that the analysis was performed with near-population data that reflected actual customer data. That work identified bill savings opportunities in the manner described above and is not speculative. Further, the ex-ante approach was used, not opposed, and therefore approved in Cause No. 45253. Mr. Flick testified he believed the previously approved ex ante approach is administratively efficient and reasonable.

In response to Kroger witness Bieber, Mr. Flick explained that the appropriate decision regarding whether lost revenues should be assigned to the rate class a switching customer originated from or is moving to requires consideration of broader factors like the number of customers in the rate classes in question. He explained that either choice could lead to unintended consequence if made in a vacuum. Mr. Flick testified the Company's proposal appropriately considers the relative sizes of the tariffs and classes in question, addresses the need for gradualism, and does not allow the migration adjustment to unduly influence the actual size of customer migrations.

Mr. Flick testified that denying or reducing the Company's requested migration amount would unduly challenge the Company's opportunity to earn the ultimately approved revenue requirement. Mr. Flick stated the Company has designed the new TOU rates and prices to be reasonably attractive to a large enough group of customers to encourage adoption, with the expectation that such migration will not impair the Company's ability to recover its revenue requirement. He testified that if migration recovery is not approved, the message would be that the Company should design less attractive pricing structures to limit migration and so as to provide appropriate recovery.

f. <u>Commission Discussion and Findings</u>. The Commission finds that Duke did not provide persuasive empirical evidence to support its assumption that 50% of Duke's customers eligible to migrate to a new rate will, indeed, migrate to that rate. The evidence demonstrates otherwise, including the research findings OUCC witness Dr. Dismukes presented on residential and small commercial customers' adoption of time-variant rates that demonstrate adoption rates are significantly below 50%. Although Duke contended that residential customers with no behavioral change will save money with TOU rates, the evidence does not demonstrate that customers who are unlikely to change their behavior with respect to the time of consumption or manner of consumption will actually move to a new rate. The adoption rates shown in the studies Dr. Dismukes referenced ranged from a low of 1% to a high of 4%. Although not an apples-to-apples comparison, Duke's adoption rate for its Dynamic Pricing Pilot approved in its last rate case fell below 1%.

Duke's arguments regarding its migration adjustment methodology, including its threshold analysis and minimum savings factors, and its concerns about comparing its proposed TOU rates to the Company's past pilots do not resolve its lack of empirical evidence to support its migration assumption. The burden is on Duke to prove its case and it failed to do so. The Commission is mindful that approving a lost revenue adjustment for lost revenue that never materializes carries a substantial risk of double recovery of revenues from Duke's ratepayers. While we recognize there may need to be some adjustment, we find it is premature to approve the adjustment level Duke proposed given the low interest in the dynamic pricing pilot and the evidence supporting an adjustment based on one to four percent adoption. The Commission finds it is reasonable to utilize Dr. Dismukes' recommendation that 16.5% of Duke's residential and commercial customers will adopt the new offered rate. For residential and small commercial customers, we find it is, therefore, appropriate to reduce the proposed revenue requirement for customer migration by $2.5 million ($2.3 million for residential customers and $0.2 million for small commercial).

15. Rate Adjustment Mechanisms.

A. Fuel Cost Adjustment (Rider 60).

i. Base Cost of Fuel.

a. Duke Case-in-Chief. Duke proposed to update its base cost of fuel in this proceeding from 26.955 mills per kWh (as established in Cause No. 45253) to 34.378 mills per kWh. Company witnesses Swez and Verderame discussed the production cost model used to simulate generation output and the associated costs used in developing the forecasted fuel and purchased power expenses. Based on this modeling, Mr. Verderame testified the Company's retail jurisdictional fuel cost assumptions for 2025 are reasonable.

b. OUCC Case-in-Chief. The OUCC recommended a reduction to Duke's forecasted fuel costs of $43,249,000. In support, OUCC witness Eckert noted Duke is proposing a $0.034378 per kWh base cost of fuel as compared to the currently approved $0.026955 per kWh base cost of fuel. He testified Duke's forecasted cost of natural gas and MISO market prices are too high because the Company used the forecasted cost of natural gas and MISO On-Peak and Off-Peak market prices for 2025 as of October 2, 2023, and as of June 28, 2024, the forecasted cost for 2025 had decreased. Mr. Eckert applied the decrease to Duke's proposed natural gas costs and to purchased power (both on- and off-peak). Mr. Eckert explained that he did not use the off-peak percentage decrease separately because the Company did not provide the off- and on-peak costs separately. As a result, Mr. Eckert applied the on-peak price to both the on- and off-peak costs, which is more conservative. Therefore, he testified the Company is requesting a base cost of fuel that is too high given current market conditions.

c. Duke Rebuttal. On rebuttal, Ms. Graft testified she disagreed with Mr. Eckert's proposed reduction of $43,429,000 to forecasted fuel expense and recommended the Commission approve the Company's proposed base cost of fuel as filed of 34.378 mills per kWh. Ms. Graft testified Duke develops its fuel cost forecasts based upon assumptions inherent as of a date certain (October 2, 2023 in the current proceeding), and while the Company recognizes that purchased power and natural gas prices have declined since October 2, 2023, and there is no evidence to indicate the prices as of October 2, 2023 are unreasonable assumptions. She testified that given the significant price volatility in the purchased power and natural gas markets that has occurred in recent history, the Company recommended the Commission approve its proposed base cost of fuel as filed.

Mr. Verderame described in his rebuttal testimony how the Company developed its generation and fuel cost forecasts utilizing a stochastic production cost model including using the best information available at the time the forecast is produced. Mr. Verderame explained the stochastic model outputs are based on 100 individual scenarios, which is designed to better capture the volatility in commodity prices that are a key component in Duke's fuel costs. Further, Mr. Verderame testified the Company's proposed base cost of fuel is based on more than just the two isolated inputs highlighted by Mr. Eckert. Company witness O'Connor described in his rebuttal testimony the Company's stochastic model and the underlying assumptions and inputs informing the model. Mr. O'Connor testified the Company's model uses clearly defined inputs, including exchange-traded energy commodity pricing, historical data on system loads and prices, and historical actual unit performance parameters in order to project future coal burns.

d. Commission Discussion and Findings. The evidence establishes that purchased power and natural gas prices have declined since October 2, 2023, there is no evidence to indicate the prices the Company used as of October 2, 2023 to develop its fuel cost forecasts are unreasonable assumptions. Further, Company witnesses Graft and Verderame explained that the cost of purchased power and natural gas prices are only two of the inputs to be considered in the Company's proposed base cost of fuel. Company witnesses Verderame and O'Connor described at length in their rebuttal testimonies the stochastic production cost model the Company uses to forecast its generation and fuel costs. Mr. O'Connor testified the Company's model uses clearly defined inputs, including exchange-traded energy commodity pricing, historical data on system loads and prices, and historical actual unit performance parameters. Company witness Verderame testified this model allows the Company to better capture the volatility in commodity prices that are a key component in the Company's fuel costs.

We agree with the Company that the cost of purchased power and natural gas prices are only two of the many inputs to be considered as part of the Company's base cost of fuel evaluation. While the OUCC's recommendation only considers two of these inputs, the record demonstrates that the Company uses a robust stochastic production cost model considering numerous inputs to forecast its generation and fuel costs. As such, we find the Company's model is a more reliable approach for purposes of forecasting fuel costs in this proceeding.

Further, while purchased power and natural gas prices have declined since October 2023, given the significant price volatility in the purchased power and natural gas markets, there is no guarantee these prices will continue to decline. We find the use of the October 2, 2023 prices are reasonable. As such, we accept the Company's proposed base cost of fuel as filed of 34.378 mills per kWh and reject the OUCC's proposed reduction of $43,429,000 to Duke's forecasted fuel expense.

ii. Fuel Inventory Tracking Request.

a. Duke Case-in-Chief. In this proceeding, the Company is proposing to build into its base rates a representative balance of coal inventory (approximately 2,333,474 tons or 45 days full load burn at a rate of 51,490 tons per day) and then track the actual inventory balance, both up and down, in the Company's quarterly FAC filings. Mr. Verderame explained the Company is proposing to track its coal inventory due to the volatile energy commodity pricing environment impacting unit dispatch and inelasticity of the coal supply chain which can cause coal inventories to fluctuate significantly over short periods of time. Mr. Verderame testified that since the Company's last rate case, Duke's coal inventory has ranged from a low of 885,433 tons (17 days of coal supply at a full load burn rate of 51,490 tons per day) in August 2021 to a high of 3,255,514 tons (63 days of coal supply at a full load burn rate of 51,490 tons per day) in December 2023. Mr. Verderame testified tracking the actual inventory balance, both up and down, in the quarterly FAC filings provides a more proactive mechanism for reflecting the changes in inventory balances in customer rates more quickly as inventory dynamics change.

b. **<u>CAC Case-in-Chief</u>.** CAC witness Glick also recommended the Company's proposal to track the level of coal inventory in rate base through its FAC filings be rejected. Ms. Glick testified the Company has not justified the value to ratepayers of its request to track coal inventory. She introduced a discovery admission from Duke that under Duke's proposal in this case, Duke's return on coal inventory would increase if Duke's actual coal inventory is higher than 45 days during a future FAC reconciliation period. She asserted it is unclear whether Duke's proposal includes a requirement that, in future FAC proceedings, Duke provide any justification for why a then-prevailing particular inventory level is reasonable. She argued that under Duke's proposal, the Company could collect a rate of return on oversupply and therefore profit for over-projecting coal burns and over-procuring coal. Ms. Glick showed that if Duke's ending coal inventory as of December 1, 2023 were used in a future FAC proceeding, that would create an annualized increase of around $5 million of revenue compared to the coal inventory (45 days' worth) proposed to be included in base rates.

c. **<u>Industrial Group Case-in-Chief</u>.** Industrial Group witness Gorman also recommended Duke's proposal to track its coal inventory through the FAC should be rejected. Mr. Gorman testified Duke has a responsibility to maintain coal inventory at sufficient levels to provide reasonable and adequate service, further, Duke's proposal to track coal inventory through the FAC imposes too much risk on customers and does not provide protection for customers from paying rates that are no more than just and reasonable. Mr. Gorman did not take issue with the company's proposal to set its coal inventory at a level sufficient to provide a 45-day supply.

d. **<u>OUCC Case-in-Chief</u>.** While the OUCC did not object to the amount of coal inventory (45 days) the Company is proposing to build into base rates in this proceeding, the OUCC recommended the Commission deny the Company's request to recover a return on fuel inventory through its FAC proceeding. Mr. Eckert argued return on fuel inventory is not a fuel cost that is eligible for recovery under Ind. Code § 8-1-2-42, the Company's inventory issues are a result of Duke's procurement practices, and the Company's proposed tracker shifts the risk of managing the Company's coal supply from shareholders to ratepayers.

e. **<u>Duke Rebuttal</u>.** On rebuttal, Company witnesses Verderame and Graft disagreed with the OUCC and intervenors' criticisms of the Company's request to track changes in coal inventory. Ms. Graft testified the Company's request is a proactive mechanism to reflect changes in inventory costs in rates more quickly as inventory dynamics change. Further, Ms. Graft explained the proposal is not one-sided – she testified it protects customers in the event of a decline in coal inventory over the level in base rates while also providing timely recovery to the Company of its costs to finance coal inventory in excess of the level in base rates. Therefore, Ms. Graft testified the Company's request is reasonable to make in the context of this rate case. Mr. Verderame also disagreed with the OUCC's contention that the Company's higher inventory levels are a result of the Company's coal procurement practices. He testified the Company forecasts its coal procurement needs using the best available information at the time; however, there are many unforeseen circumstances that alter the Company's actual coal consumption, including weather, unplanned outages, and energy market price volatility.

Ms. Graft also responded to other issues raised by Mr. Eckert regarding the Company's proposal. Ms. Graft responded to Mr. Eckert's claim that a return on fuel inventory is not recorded in FERC Account 501 and therefore is not eligible for recovery through the FAC. She testified there is no reference to the Uniform System of Accounts in Ind. Code § 8-1-2-42(d) and the statute allows for a change in rates due to changes in the "cost of fuel." Pet. Ex. 29 at 12-13. Ms. Graft testified the cost of capital to procure fuel inventory is a cost of fuel, the Commission has allowed other costs to be recovered through the FAC that are not technically fuel, and Ind. Code § 8-1-2-42(a) gives the Commission discretion to approve other tracking mechanisms.

f. **Commission Discussion and Findings**. Duke argued that it should be permitted to track its cost of fuel through its FAC pursuant to Ind. Code § 8-1-2-42(a). We decline to authorize such tracking of costs. In reaching this decision, we note:

> When determining whether costs should be tracked, we have generally considered whether the expenses are "collectively or potentially significant, whether they are potentially variable or volatile, and whether they are largely outside the utility's control . . . We also consider the utility's request from a broader perspective by reviewing "the utility's risks related to its operating costs and the other tracking mechanisms it has in place. We have generally found that revenue or cost trackers tend to make utilities less accountable for their actions and thus, should remain limited to ensure the utility is properly incented to manage its overall operating costs . . . If utilities can "recover the majority of their variable costs through trackers, they have no incentive to come before the Commission and account for other, non-tracked, decreasing costs or increasing revenues.

S. Ind. Gas and Elec. Co., Cause No. 43839 at 94 (IURC Apr. 27, 2011) (citations omitted).

In Indiana-American's recent base rate case (Cause No. 45870), the utility sought, in part, to track its production costs by comparing its actual expenses to the amount approved for recovery and embedded in base rates with the total difference being treated as a regulatory asset or liability in the next rate case. The utility asserted that it sought this mechanism to protect itself and customers from volatility in these costs. In rejecting the utility's request, the Commission found that while the utility "speculated about the potential impact of market fluctuations and price volatility," the evidence did not show that "that the variability in costs will expose [Indiana-American] to the risk of not meeting its service obligations or shareholders to not earning a reasonable return, or that the requested relief will fundamentally benefit ratepayers." *Indiana-*

American Water Company., Inc., Cause No. 45870 at 136 (IURC Feb. 14, 2024). The Commission described this balancing as "essential" and one that is "at the heart for the regulatory compact." *Id*.

In the current Cause, Duke's evidence establishes that the coal market is volatile and that it rises and falls due to factors outside Duke's control. However, as in Cause No. 45870, there is insufficient evidence to establish that such variability threatens Duke's ability to meet its service obligations, that shareholders will not earn a reasonable return, or that the relief will fundamentally benefit ratepayers. While Duke indicated that there is a potential for customers to receive a prompt credit in an FAC proceeding, we find that such a possible benefit is insufficient to overcome this other lack of evidence. We do not believe it is in the public interest to remove an incentive to engage in efficient and prudent management of its inventory.

For all of these reasons, we decline Duke's request to track its coal inventory through its FAC.

iii. <u>Duke's Fuel Procurement Strategy and Economic Dispatch</u>. Certain intervenors raised concerns regarding the Company's coal procurement strategy and the dispatch practices of the Company's coal-fired generating fleet. CAC witness Glick argued the Company is procuring more coal than it needs and asserted the Company is deliberately over-forecasting its coal burn. Ms. Glick explained that Duke has used a Supply Offer Adjustment at Gibson since August 2021 and Cayuga since October 2021. She explained that this adjustment allows Duke to adjust the coal cost that it uses to calculate a unit's offer into the MISO market. She said Duke indicated that it expects to continue utilizing the adjustment at Gibson Units 1-5 and Cayuga Units 1-2 as a normal course of business. She asserted that the Supply Offer Adjustments coupled with the over-buying of coal can give the Company an incentive to operate the coal fleet more than is economic. She also noted that Duke has provided no analysis on the cost and risk of a shortage, or the cost of storing and handling an oversupply; moreover, there has been no time when Duke could not operate due to constraints on coal deliveries.

Ms. Glick accordingly recommended that the Commission instruct Duke to revise its coal burn projection to procure in the middle of its projected range rather than the upper end and also recommended the Commission instruct Duke to provide transparent documentation behind its coal burn projection and explain any substantial deviation between historical data and projected need. Ms. Glick also recommended that the Commission advise Duke that it will not allow recovery in future FAC dockets of excess fuel costs incurred from uneconomic commitment and dispatch practices resulting from reliance on inflated coal-burn projection.

On rebuttal, Company witness Verderame explained the Company submits its coal procurement strategy for review by the OUCC and the Commission via its FAC proceeding, and neither the Commission nor the OUCC have identified any issues with the Company's coal procurement strategy. Further, Mr. Verderame responded to Ms. Glick's allegations that the Company inflates its coal projections, is procuring more coal than needed, and the supply offer creates an incentive for the Company to over-buy coal.

Company witness O'Connor's testified at the hearing that the Supply Offer Adjustment issue has no impact on the Forward-Looking Test Period in this Cause. Further, the Commission previously found in *Duke Energy Indiana, LLC*, Cause No. 38707 FAC 139 at 7 (IURC March 27, 2024) that the Company had laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO. Given today's energy market price volatility, fuel inventory supply chain constraints, and shifting dynamics in the market fuel resource mix impacting fuel inventories and reliability, the Company's use of the Supply Offer Adjustment can serve as an effective tool to protect against otherwise larger swings in fuel inventories over time. Duke must continue to provide support for any supply offer adjustment in future FAC filings, and we believe an FAC proceeding affords a focused, statutorily afforded place for these issues to be deliberated and considered. Further, the record demonstrates Duke regularly submits its fuel procurement strategy to the Commission in the FAC proceedings where a focused review is afforded. These issues have been deliberated at length in Duke's prior FAC proceedings, and we will consider them in such proceedings going forward as required.

Further, regarding the Company's dispatch process and decisions, the Industrial Group, Sierra Club, and CAC generally contend that the Company's coal fleet, mainly Edwardsport, is not being dispatched economically. This issue too has been the subject of much debate in the Company's prior FAC proceedings, and we see no reason to further address the issue here. In *Subdocket for Review of Duke Energy Indiana, LLC's Generation Unit Commitment Decisions*, Cause No. 38707 FAC 123 S1 at 23 (IURC March 17, 2021), we found:

> It is not appropriate for the units at Gibson, Cayuga and Edwardsport to be offered to MISO using a commitment status offer of Economic at all times. Despite the assertions of Sierra Club, CAC and other Intervenors, this can lead to inefficient outcomes for Duke customers. Given the varying characteristics and considerations with each specific Duke generating unit, we believe the Company's unit commitment decisions during the reconciliation period were reasonable.

For these reasons and based on the evidence, we reject the intervenors' recommendations with respect to these dispatch decisions.

iv. OUCC and Intervenor Response Deadline. Mr. Eckert recommended the current agreement allowing the OUCC and intervenors to file FAC testimony 35 days after Duke files its petition and testimony should be continued. Ms. Graft testified on rebuttal that this process has worked well and she agreed with Mr. Eckert's recommendation. We therefore approve the continuation of the process whereby the OUCC is given 35 days to review the Company's FAC application and file FAC testimony. No party objected to this, and it has worked in practice.

B. Environmental Compliance Adjustment (Rider 62).

i. Duke Case-in-Chief. Due to variability in reagent costs, Duke proposed several changes to its ECR Tracker as set forth in the direct testimony of Company witness Lilly, Duke's Exhibit 5 at 25-29. As part of its proposal, the Company is proposing to continue tracking process chemicals and reagent costs associated with operating generating units' environmental controls through the ECR. Duke proposes embedding $27.4 million in test year

O&M for process chemical and reagent costs and will track actual costs above and below this amount.

ii. <u>OUCC Case-in-Chief</u>. OUCC witness Armstrong testified the Company's proposal to continue tracking process chemicals and reagent costs associated with operating generating units' environmental controls above and below the test year amount through the ECR is reasonable. She also stated the test year amount of $27.4 million is consistent with actual reagent costs over the past three years and is a reasonable amount to include in the test year.

iii. <u>CAC Case-in-Chief</u>. Dr. McCann proposed that because coal ash is produced from burning fuel, coal ash costs should be allocated based on production energy or a sales allocator. He also proposed changing the cost assignment of the coal ash portion included in Rider 62 to a sales allocator. Dr. McCann also proposed to use a sales allocator for Rider 73. Additionally, CAC witness Dr. McCann raised concerns regarding the Coal Ash and Renewable Rider Allocations.

iv. <u>Industrial Group Cross-Answering Testimony</u>. Mr. Collins disagreed with Dr. McCann's recommendation to change Duke's allocation method from a demand basis to an energy basis for coal ash costs. Mr. Collins explained that coal ash ponds are fixed cost structures associated with generation production facilities and thus, it is appropriate to allocate these costs associated with coal ash ponds to customer classes on a demand basis, which is the same manner used for all other production plant.

v. <u>Duke Rebuttal</u>. Ms. Diaz disagreed with Dr. McCann's allocation for coal ash and further endorsed continuing the production demand allocation methodology for both Rider 62 for coal ash and Rider 73. Ms. Diaz explained that Dr. McCann's recommendation to allocate the regulatory asset associated with coal ash closure costs previously approved under the federal mandate statute on a production energy or sales allocator basis is inconsistent with the past approach of allocating these costs on a demand basis and ignores the fact that the ash ponds are associated with Duke's production facilities, which are designed to meet the demands of Duke customers. She explained that coal ash pond costs are normally included in the production plant account that also includes the costs of furnaces, boilers, coal preparation equipment and other related equipment used in generating stations. She testified all this associated production plant must be appropriately sized for the generating unit used in meeting customers' peak demands. Ms. Diaz testified it is appropriate to allocate these costs to customer classes on a demand basis, just like all other production plant is allocated. She further testified because the costs in question are tied to compliance with federal and state environmental requirements related to closing and ongoing management of the coal ash ponds, they are residual in nature. Ms. Diaz explained that residual and end of life costs typically and logically follow the cost of the plant, which is appropriately allocated based on a demand basis. She testified that the Company has also proposed in this proceeding to include coal ash costs in depreciation rates, and the depreciation expenses are allocated based on demand. Ms. Diaz explained that coal combustion residuals, unlike coal, does not have energy potential and is not a fuel. She testified the environmental liability that the Company is now tasked with managing is an environmental compliance cost that did not exist when the coal was first burned, but arose years later, and another reason that applying demand allocators is consistent with treatment of end-of-life costs associated with production plants.

vi. Commission Discussion and Findings. We find it is appropriate to allocate coal ash pond closure and coal ash management costs to customer classes on a demand basis, just like all other production plant is allocated. The recovery of similar costs through Rider 62 does not change their appropriate cost of service allocation. Ms. Diaz appropriately notes that the Company has also proposed in this proceeding to include coal ash costs in depreciation rates, and the depreciation expenses are allocated based on demand. No party disputes that these costs are associated with an environmental liability that is associated with end-of-life of the plant, and applying demand allocators is consistent with treatment of end-of-life costs associated with production plants.

As for changing the cost assignment in Riders 62 and 73 to a sales allocator, we are not persuaded by Dr. McCann's arguments because Duke's use of production demand allocators is consistent with the treatment for similar costs included in base rates as explained by Ms. Diaz.

We note that other issues related to Rider 62 and CCR costs were previously discussed in the Environmental Sustainability section of this order. Ultimately, we find the Company's proposed changes are reasonable and should be approved.

C. TDSIC Adjustment (Rider 65).

i. Duke Case-in-Chief. In this proceeding, the Company is proposing to roll the original cost investment and accumulated depreciation of in-service TDSIC plant (TDSIC 1.0 and 2.0[16]) as of the end of the future test period into base rates. This includes the 80% of in-service plant that is eligible for inclusion in the TDSIC Tracker, as well as the 20% that is deferred for rate case recovery pursuant to Ind. Code ch. 8-1-39. Further, the Company proposed that TDSIC O&M expense and PISCC not be included in base rates, but continue to be tracked and recovered in the TDSIC Tracker. Company witness Lilly testified this treatment is being proposed because the TDSIC project-related O&M is non-recurring and variable in nature, and the O&M for the TDSIC inspection-based projects can also fluctuate. Ms. Lilly testified the PISCC experience similar variations due to being non-recurring and variable in nature.

ii. OUCC Case-in-Chief. OUCC witness Lantrip recommended approval of the Company's proposed treatment of its TDSIC Tracker. He noted that the change will be useful to the OUCC in tracking individual projects. He supported the exclusion of incremental TDSIC O&M and PISCC expenses from base rates because Mr. Lantrip testified these costs are non-recurring and will be better adjusted through the rider process.

iii. Commission Discussion and Findings. To the extent elements of Duke's TDSIC plan are in service by the close of the test year, we find that that they are used and useful and are properly included in Duke's rate base upon which it is authorized a return. We find the Company's proposal and changes to Rider 65 as set forth in its case-in-chief, including its

[16] As noted above, the Indiana Supreme Court affirmed the Commission's Order regarding Cause No. 45647. Due to mootness, we do not address the parties' testimony nor arguments relating to the Industrial Group's interim treatment recommendation.

proposal to exclude TDSIC O&M expense and PISCC from base rates and continue to track and recover those amounts in the TDSIC Tracker, are reasonable and should be approved. Ultimately, we find the Company's proposed changes to its TDSIC Tracker are reasonable and should be approved.

D. Energy Efficiency Adjustment (Rider 66). In its case-in-chief, the Company proposed to reset current rates to remove lost revenue amounts and adjust the revenue conversion factors in its Energy Efficiency Tracker. No party took issue with the Company's proposed changes to the Energy Efficiency Tracker and we find the Company's proposed changes are reasonable and should be approved.

E. Credits Adjustment (Rider 67). In its case-in-chief, the Company proposed to include additional TCJA credits, the credits for the IGCC facility tax incentives and the Two-Step Rate Adjustment (as previously discussed) in Rider 67. The Company proposed to add and remove other various credits as described in Company witness Lilly's Direct Testimony, Duke's Ex. 5. No party took issue with the Company's proposed changes to Rider 67 and we find the Company's proposed changes are reasonable and should be approved.

F. Regional Transmission Operator Non-Fuel Costs and Revenue Adjustment (Rider 68). In its case-in-chief, the Company proposed to update the amounts embedded in base rates for the regional transmission operator non-fuel costs and transmission revenues to reflect forecasted levels for 2025 but did not propose any changes to the operation of this tracker. No party took issue with the Company's proposed changes to Rider 68 and we find the Company's proposed changes are reasonable and should be approved.

G. Reliability Adjustment (Rider 70).

i. Duke Case-in-Chief. We note that as approved in Duke's last base rate case, Cause No. 45253, Duke's SRA Rider reconciles the variance in Duke's PowerShare program costs from the $9.911 million currently embedded in base rates. The Company proposed two changes to its Reliability Adjustment Tracker in its case-in-chief. First, the Company proposed retaining a sharing mechanism for net margins realized on Short-Term Bundled Non-Native Sales. The Company proposed to reset the base amount to zero and to share 100% of net margins up to a $5 million threshold with customers. Any positive net margins above that level would be shared 50/50 between customers and shareholders. Second, the Company proposed to update the proposed annual base amount for PowerShare bill credits in base rates to zero and to recover actual costs for the program entirely through Rider 70.

ii. OUCC Case-in-Chief. Mr. Lantrip recommended only approving Duke's $5 million Short-Term Bundled Non-Native Sales threshold conditioned on approving a 75%/25% ratepayer/shareholder allocation split on revenues exceeding that threshold, instead of Duke's proposed sharing allocation. Mr. Lantrip testified the Company has not presented sufficient evidence demonstrating why the $5 million threshold was chosen or the propriety of this proposed threshold. He stated Duke forecasts it will be years before these bundled contracts are expected to achieve positive margins, but this does not justify the new sharing threshold and percentages Duke proposes. He testified Duke's alternative proposed allocation split with ratepayers was excessive.

iii. Duke Rebuttal. On rebuttal, Company witness Sieferman testified the Company proposed to flow back all net positive margins to customers up to the $5 million threshold. She stated that given customers are receiving all net positive margins up to the $5 million threshold level, equal sharing of any margins above that threshold is not excessive. Further, she explained the Company's shareholders are taking on the risks of any net negative margins and are not able to retain any positive margins unless the $5 million threshold is exceeded. She testified the 50/50 level proposed by the Company is a more balanced approach that allows for sharing with customers but also allows for some profits to be maintained by the Company in the event the margin is greater than the threshold level.

iv. Commission Discussion and Findings. No party took issue with the Company's proposal to update the proposed annual base amount for PowerShare bill credits in base rates to zero and to recover actual costs for the program entirely through the Reliability Tracker. We find the Company's proposal is reasonable and we approve it. Further, regarding the Company's proposed sharing mechanism for net margins realized on Short-Term Bundled Non-Native Sales, we agree with Company witness Sieferman that the Company's proposal represents a more balanced approach than the OUCC's recommendation. The Company's proposed mechanism allows for sharing with customers, while allowing for some profits to be maintained by the Company in the event the margin is greater than the threshold level. As such, we find the Company's proposal, as well as its other proposed changes, are appropriate and should be approved.

H. Federally Mandated Cost Adjustment (Rider 72). In its case-in-chief, the Company testified Rider 72 rates are currently at $0 and will remain there until future federally mandated costs are approved for recovery. Despite having no costs, Company witness Lilly testified the Company is proposing to continue Rider 72 to have a ready mechanism via which to track likely future North American Electric Reliability Corporation cybersecurity costs, as well as any other federally mandated costs. The OUCC testified it did not oppose this request, and no other party took issue with the Company's proposal. Ms. Lilly also testified that Duke proposed to reset its Rider 72 tariff numbering and to update the allocation factor pages of the tariffs to reflect the approved cost of service study allocations to be used for the tracker. No party expressed a position regarding this proposal. We find the Company's proposal to continue Rider 72, as well as its proposed other changes to be reasonable and are approved.

I. Renewable Energy Project Adjustment (Rider 73). Ms. Sieferman explained Duke's proposed updates to its Renewables Tracker regarding the amounts embedded in base rates and she provided the Company's rationale for these changes. The OUCC testified it did not oppose these updates, and no other party took issue with the Company's proposed changes. Thus, we find the Company's proposed changes are reasonable and are approved.

J. Load Control Adjustment (Rider 74). Ms. Lilly explained Duke's proposal that upon implementing new rates resulting from this Cause, the utility will remove the level of expenses included in the base rates. Ms. Lilly testified the Company will also change the revenue conversion factors used to calculate revenue requirements to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding. No party took issue with the Company's proposed changes to Rider 74 and we find the Company's proposed changes are reasonable and are approved.

16. Other Issues.

A. Tariff Issues.

i. EZ Read Program.

a. Duke Case-in-Chief. Mr. Colley explained the EZ Read Program is a pre-advanced metering infrastructure deployment program in which participating customers telephonically report their meter reading to the Company on a monthly basis. This program removed the meter reading responsibility from the Company for eleven months of each calendar year. Duke, pursuant to Commission approval, closed the program to new customers. Mr. Colley estimated that the program would only have approximately 480 customers by May 2024. The Company proposed to sunset the EZ Read Program due to a decrease in customer participation, largely due to participants not complying with program requirements. He said once the program is ended, customers could switch to an Advanced Metering Infrastructure ("AMI") meter at no incremental cost or begin service as an AMI opt-out customer which carries a monthly $17.50 charge. Mr. Colley explained that the Company proposes a six-month migration period from the date of an approving order to provide customers time to determine which option is best for them and to work with the Company through the change. During any migration period, Company customers will not be charged any fees and will share multiple communications to current EZ Read customers explaining the change, the transition options available, and the process for exchanging the current meters, if required.

b. OUCC Case-in-chief. Mr. Hanks noted some customers do not want to use AMI due to privacy or data security concerns and that customers who opt-out of AMI would be required to pay a $17.50 monthly charge. He argued that Duke's proposal would punish customers that may still want to use the program as the alternatives require a move to tariff with a monthly charge.

c. Duke Rebuttal. In rebuttal, Mr. Colley reiterated his direct testimony and explained the program has significantly declined over the years, and much of the program's operations must be done manually, which is costly.

d. Commission Discussion and Findings. The evidence supports discontinuing this program due to the decrease in customer participation in light of the time and resources that the Company would otherwise be required to expend managing the program. Additionally, the record demonstrates that customers will be given ample notice of the program sunsetting and the Company will have call specialists trained on the transition to answer questions about the options to shift to a new metering and billing solution. The Commission therefore approves the Company's request to sunset the EZ Read Program, subject to it implementing its transition plan.

Duke proposed other modifications, both clerical and substantive, to its retail electric tariff, as discussed in the direct testimony of company witness Flick. Besides what has been addressed in this section, these proposed modifications are unopposed. We find each of these unopposed proposals to be reasonable and they are approved.

ii. **<u>Final Tariff</u>.** We have discussed at length issues related to rate design and the Company's resulting tariff and have made findings on such. Unless otherwise addressed in this Order, the Company's tariff as presented by witness Flick, Pet. Ex. 7, Attachment 7-A (RAF), is approved.

B. **<u>Regulatory Accounting Treatment</u>.** In this proceeding, the Company requested the following regulatory accounting treatment: (1) the continuation of the reserve accounting concept established in Cause No. 45253 for distribution vegetation management O&M costs and expansion of the reserve accounting concept to include transmission vegetation management O&M costs; (2) new deferral authority and future recovery of costs to achieve corporate restructuring savings that are reflected in the forecasted test period; (3) new deferral authority associated with potential future statutory income tax rate changes; and (4) deferral authority for costs associated with the CCS Study at Edwardsport. On rebuttal, the Company withdrew its request to create a regulatory asset to defer its costs to achieve corporate restructuring savings. We have previously discussed Duke's request for deferral authority for certain remaining net book value of generation assets and cost of removal upon retirement. We will address Duke's requests with respect to deferral authority related to costs associated with the CCS Study at Edwardsport, income tax differences and to continue and expand the reserve accounting concept established in Cause No. 45253 for vegetation management costs in the following sections.

i. **<u>CCS Front-End Engineering Design ("FEED") Study</u>.**

a. **<u>Duke Case-in-Chief</u>.** Mr. Hoeflich explained Duke received a U.S. Department of Energy grant to fund the FEED Study to evaluate the feasibility of capturing and storing CO_2 from the flue gases of the two heat recovery steam generators at Edwardsport. He stated the results of the FEED study will provide cost estimates, risk assessments, and community impact/benefit analysis that can be used to determine if the project should advance to the next phases of project execution. Mr. Hoeflich stated that the study is anticipated to cost $17,163,453, of which the grant will provide an estimated $8,192,430 and Duke will be responsible for the balance—approximately $8,971,023.[17] Duke seeks Commission approval to defer the utility's costs for inclusion in rates in a future proceeding. Mr. Hoeflich said the FEED Study results could be used in evaluating CCS projects at other Indiana generation sites, particularly at future natural gas combined cycle generating plants. Mr. Hoeflich further argued it is prudent and reasonable for the utility to undertake the Study due to the principal role of CCS technologies in the EPA's proposed rule under Section 111 of the Clean Air Act.

17 We note Duke's response to Industrial Group Data Request 2.06 (admitted as Attachment BI-3 to CAC Exhibit 3) in which Mr. Hoeflich is listed as the sponsoring witness indicates the total cost to complete the FEED Study is $18,133,803.

b. **<u>CAC Case-in-Chief</u>.** Mr. Inskeep testified it is not reasonable for Duke to spend its share of the FEED Study cost $9.9 million[18] on the CCS Feed study and receive approval to defer such costs. Mr. Inskeep testified that pursuit of the CCS project is not consistent with the Company's most recently submitted IRP and is also not consistent with the Company's findings from its subsequent IRP modeling refreshes. Further, Mr. Inskeep argued that CCS is not necessary to comply with the recently promulgated EPA greenhouse gas regulations. He testified that while CCS is one possible compliance pathway, it is not the only option for reducing Edwardsport's emissions or for Duke to achieve compliance. Mr. Inskeep also cited the Commission's Order rejecting the CCS study in Cause No. 43653 and testified the same concerns in that case are still present. Mr. Inskeep further testified CCS at Edwardsport faces extraordinary financial, technological, geological, project execution, and policy uncertainty and risks.

c. **<u>OUCC Case-in-Chief</u>.** OUCC witness Wright recommended the Commission reject Duke's proposal to defer the CCS FEED study costs. Mr. Wright testified the technological feasibility of such a system has not been determined, the final system would be very costly, and Duke has more affordable alternatives to comply with the recent EPA rule on carbon emissions. He testified building a CCS system would be inconsistent with Duke's latest IRP, which has Edwardsport switching fuels to only natural gas combustion by 2035. He testified the projected capital costs and annual operating expenses for a CCS system at Edwardsport would substantially increase the operating costs. Further, Mr. Wright argued that the benefits of the FEED study should extend beyond Indiana, and a portion of its costs should therefore be allocated to other Duke Energy Corporation jurisdictions. Mr. Wright also cited to the Commission's Order in Cause No. 43653 rejecting the previously proposed CCS study and testified the Commission's concerns over the study proposed in that proceeding due to the uncertainty regarding the technological feasibility, also apply to this FEED study proposal. Mr. Wright asserted that the evidence does not sufficiently support a finding that the measurable benefits of the carbon sequestration study merit the material cost to rate payers at this time.

d. **<u>Industrial Group Case-in-Chief</u>.** Industrial Group witness Gorman recommended denial of Duke's proposal to defer the CCS FEED study costs because Duke has not demonstrated that continued operation of Edwardsport as an IGCC on syngas is economic. Mr. Gorman testified switching to natural gas is more economic and would reduce carbon emissions by over 50%. Mr. Gorman contends that rather than spending ratepayer money to investigate unproven CCS technology at Edwardsport, Duke should achieve carbon reduction by operating Edwardsport on natural gas.

e. **<u>Sierra Club Case-in-Chief</u>.** Mr. Comings testified it is unlikely that the cost of evaluating CCS at Edwardsport should be included in rates at any point and testified that if these costs are presented in such a future case, the Company should have to justify them by showing the prudency of continuing to pursue CCS.

f. **<u>Duke Rebuttal</u>.** On rebuttal, Company witness Hoeflich testified the current environment, which is marked by advancements in CCS technology,

18 We note Mr. Inskeep's identification of $9.9 million as Duke's share of the FEED Study cost is based upon Duke's response to Industrial Group Data Request 2.06 (admitted as Attachment BI-3 to CAC Exhibit 3).

legislative support, and robust financial incentives, supports the prudence of moving forward with the FEED Study at Edwardsport and the Company's deferral request. He testified that significant advancements and changes have occurred since the Commission's decision in Cause No. 43653, and, as such, the uncertainties raised by the Commission in that cause have been alleviated. He explained the significant advances and changes include the following: (1) a differing scope between the previous CCS work and the current work, that is, while the previous CCS work at Edwardsport focused on pre-combustion capture of carbon dioxide, which involves capturing carbon dioxide from syngas before it is combusted, the current FEED study would focus on post-combustion capture, which captures carbon dioxide following combustion in the power block and allows for carbon dioxide capture regardless of whether the power block is firing syngas or natural gas, significantly enhancing the flexibility and applicability of the CCS technology; (2) the availability of federal funding and tax credits, as well as definitive legislation, when those were not available in Cause No. 43653; (3) advancements in CCS technology, as well as new legislation providing funding and regulatory options for CCS which clarifies the regulatory environment and underscores the importance of CCS technology.

Mr. Hoeflich testified these factors collectively create a favorable context for moving forward with the FEED Study at Edwardsport. Mr. Hoeflich also responded to OUCC witness Wright's argument that a portion of the study's costs should be allocated to other Duke Energy jurisdictions. Mr. Hoeflich testified that allocating the costs to other jurisdictions would not be appropriate, as the benefits of the FEED Study are specific to Edwardsport due to its unique geological location in the Illinois Basin and operational characteristics, and Company affiliates will not have access to FEED Study results that differ from those study results that are available to other utilities. Further, regarding the OUCC and intervenors' recommendations that the Commission should not approve the Company's request to defer the FEED Study costs due to feasibility and affordability concerns, Mr. Hoeflich testified the Commission retains the authority to review the outcomes of the FEED Study and to determine the appropriateness of cost recovery in a future case.

g. <u>Commission Discussion and Findings</u>. We agree with Duke that circumstances in which Duke raises its CCS study in the current Cause are different than those surrounding the utility's request for approval of a CCS study in Cause No. 43653. We noted the following concerns when we rejected the CCS study in the 43653 Order:

> As we noted in our Orders that led to the filing presented in this Cause, Commission recognizes there are many uncertainties related to the long-term management of [carbon dioxide], including the potential development of a [carbon dioxide] interstate pipeline as an alternative to local sequestration. The exact nature of carbon regulations and the date they might take effect is uncertain. Congress has not passed any definitive legislation requiring the limitation of carbon emissions. Further, while the EPA has proposed restrictions on carbon emissions from new power plants, any potential regulations concerning existing power plants is speculative in terms of both timing and result. Also, uncertainties exist regarding the technological feasibility of local carbon sequestration and pipeline transport of [carbon dioxide]. Finally, Duke was not selected to receive additional federal funding to support its study. Therefore, we conclude that the evidence does not

> sufficiently support a finding that the measurable benefits of the carbon sequestration study merit the material cost to ratepayers at this time.

Duke, LLC, Cause No. 43653 at 20 (IURC Jan. 23, 2013).

The evidence in the current Cause demonstrates these concerns have been alleviated by changes in legislation, the scope of Duke's proposed project, and the federal funding Duke has received from the DOE. Unlike in Cause No. 43653, EPA has now promulgated greenhouse gas regulations and CCS technologies that play a principal role in EPA's proposed rule under Section 111 of the Clean Air Act.

Further, the scope of Duke's proposed CCS project is different than that previously proposed in Cause No. 43653. As Ms. Hoeflich explained in rebuttal, the previous CCS work at Edwardsport focused on pre-combustion capture of carbon dioxide, which involves capturing carbon dioxide from syngas before it is combusted. The study at issue in the current Cause would focus on post-combustion capture, which captures carbon dioxide following combustion in the power block. Thus, unlike the earlier project, the current study would examine a process that allows for carbon dioxide capture regardless of whether the power block is firing syngas or natural gas, significantly enhancing the flexibility and applicability of the CCS technology. Additionally, the risks and costs associated with a carbon dioxide pipeline at issue in Cause No. 43653 are not present with the current FEED study due to local sequestration at the site. This change of scope addresses many of the technological concerns with the original project as well as the risks and costs associated with the carbon dioxide pipeline at issue in Cause No. 43653. Further, unlike in Cause No. 43653, Duke was selected to receive significant federal funding from the U.S. Department of Energy for this project, which was not the case in the prior cause.

We further note that Duke's request is consistent with the Commission's General Administrative Order ("GAO") 2022-02. The Commission stated in this GAO that it "encourages jurisdictional utilities to explore possible grant and low-cost loan options that would reduce the cost of present and future projects needed to provide utility service." GAO 2022-02, Appendix A. The Commission further stated that "the prudent application for, and use of, these funding opportunities may assist in the utility provision of safe and reliable service at just and reasonable rates . . ." GAO 2022-02 at 1.

We appreciate the concerns raised regarding the technical feasibility of the project and also the concerns that running Edwardsport on syngas is not economic; however, the concerns, while relevant, are premature and not persuasive. The study will assess the feasibility and costs of CCS, so a determination regarding the feasibility and economics of CCS versus natural gas operations at the plant cannot reasonably be determined until completion of the study. The study results will also provide information the utility can more thoroughly apply to its upcoming IRP to help determine whether the utility should move forward with a CCS project. We find the cost-sharing required by the grant to be a reasonable cost for such information which will place the utility, interested parties, and the Commission in a position to make a more informed decision in the future whether the utility should move forward on a CCS project at Edwardsport.

Mr. Inskeep argued against deferral of the study costs because CCS is not necessary to comply with greenhouse gas regulations and CCS is not the only option for reducing Edwardsport's emissions or for Duke to achieve compliance. Similarly, the CAC noted that Congress still has not passed legislation specifically addressing carbon dioxide emissions and, as such, the new carbon emissions rule is still vulnerable to the type of legal challenge that has overturned previous EPA rules on carbon emissions. While these statements are true, the study results, the utility's cost of which is reduced by the U.S. Department of Energy funding, will place the utility in a position to determine whether such an approach, even though it may not be legally required, is the appropriate long-term approach.

Further, as Company witness Hoeflich acknowledged in his rebuttal testimony, in granting the Company's request to defer these costs, the Commission retains the authority to review the outcomes of the FEED study and to determine the appropriateness of the cost recovery in a future case. Thus, any cost recovery will be subject to future scrutiny by the Commission, ensuring that only prudent and reasonable costs are recovered.

The Industrial Group also argued the Commission should deny inclusion of the FEED Study because carbon reduction can be achieved more economically by operating Edwardsport on natural gas. We have already established why permanently transitioning to natural gas is not a prudent decision at this time and as such we decline to find the Industrial Group's argument to be a basis to deny Duke's FEED Study request.

For these reasons, we find Duke's request to defer the costs associated with the CCS FEED study is appropriate and should be approved. As noted above, Mr. Hoeflich's FEED Study cost estimates in his direct testimony—$17,163,453—and the estimated cost in Duke's response to the Industrial Group's Data Request 2.06—$18,133,803—are inconsistent. We note these costs are estimates and the exact dollar amount is not determinative to our decision regarding Duke's request as the actual amount will be reflected in Duke's next rate case.

Further, we reject OUCC witness Wright's recommendation that a portion of the study costs should be allocated to other Duke jurisdictions. The record demonstrates the study will be specific to Edwardsport given its unique geographic and operating characteristics and will not be shared with other affiliates. Thus, we find such allocation is inappropriate.

ii. Future Statutory Income Tax Changes.

a. Duke Case-in-Chief. In this proceeding, the Company is requesting authority to defer all calculated income tax differences resulting from any future change in statutory income tax rates as a regulatory asset or liability, as applicable, until the effect of the statutory income tax rate change can be fully reflected in the Company's rates. Company witness Graft testified in the event of future changes in either the statutory federal or state income tax rate, the Company would propose to file a petition in a new docket seeking an adjustment to rates to reflect the difference between (1) the amount of federal or state income taxes that the currently effective rates were designed to recover and (2) the amount of federal or state income taxes that would have been included in the design of currently effective rates had those statutory income tax rate changes been in effect at that time.

Ms. Graft testified the Company's request is reasonable because the TCJA and resulting investigation taught that tax rate changes can be very material, they can take effect abruptly, and they are completely outside the Company's control. Accordingly, Ms. Graft testified that being prepared for future changes in the income tax rates is a "lesson learned" from the enactment of the TCJA and the ensuing Commission investigation. She further testified that it is reasonable for the Company to make this request in the context of this rate case proceeding to be better prepared for future changes.

b. <u>OUCC Case-in-Chief</u>. OUCC witness Latham recommended denial of the Company's request for authority to defer calculated income tax differences resulting from future changes in statutory income tax rates as a regulatory asset or liability. Mr. Latham testified federal corporate income tax rates and Indiana state corporate income tax rates are historically low, and Indiana ratepayers did not receive any balancing account benefit while investor-owned utilities enjoyed steadily decreasing rates between July 2012 and July 2021. He stated that with tax rates having trended lower, Duke seeks to have ratepayers assume the more probable risk of potential tax rate increases. Further, he testified Duke has not presented evidence or justification that any state tax change is either imminent or that multiple tax changes would lead to the level of volatility that such a balancing account would be needed to alleviate such unpredictability. Mr. Latham testified any state or federal tax rate changes should be incorporated as they traditionally have been, through base rate cases or in the event the Commission determines to address such changes consistently among affected utilities through an investigation case. As such, he testified the Company's request in this case should be denied.

c. <u>Duke Rebuttal</u>. On rebuttal, Ms. Graft reiterated the Company's request and explained the Company is only requesting the ability to defer these differences until such time as an order is received in the separately docketed proceeding. Ms. Graft testified the Company's proposal would work precisely as was implemented in the Commission investigation following the enactment of the TCJA. Ms. Graft testified the Company's proposal is consistent with the Commission's finding Cause No. 45023 S3 and Mr. Latham's position is not.

d. <u>Commission Discussion and Findings</u>. As we ruled in *Sycamore Gas Co.*, Cause No. 45032 S3 at 6 (IURC 10/19/2018), "taxes are a pass-through expense, a change in the federal income tax rate should have no substantive bearing on whether a utility is or is not earning its authorized return." We also noted that "the nature of the income tax component of the revenue requirement makes it different than many types of expenses because the rate of the burden is defined in statute rather than dependent on the management actions of the utility." *Id*. Duke is not requesting a rider, rather Duke is merely requesting authority to file a docketed proceeding to adjust rates solely for the mathematical effect of future tax rate changes and deferral authority until such changes can be reflected in rates. This is no different than the process we ordered in Cause No. 45032.We therefore grant Duke's requested authorization.

iii. <u>Vegetation Management Costs</u>. In this proceeding, Duke proposed to continue the cumulative reserve accounting approach for its distribution vegetation management O&M costs the Commission approved in Cause No. 45253 and is proposing to expand it to include both transmission and distribution vegetation management O&M costs. Specifically, Company witness Graft explained the Company proposed to track expenditures both above and below the amount proposed for inclusion in base rates in this proceeding of approximately $60.1 million ($44.8 million distribution, $15.3 million transmission). Ms. Graft testified the Company's proposal is reasonable because vegetation management is key to maintaining reliability, and including both the distribution and transmission functions in the reserve accounting approach allows for additional flexibility in allocation of resources to this work.

No party took issue with Duke's proposal to continue the cumulative reserve accounting approach the Commission approved in Cause No. 45253 for the Company's distribution vegetation management O&M costs, nor did any party take issue with the Company's proposal to expand the approach to include both transmission and distribution O&M costs moving forward. Therefore, we find Duke's request to reasonable and we approve the request.

C. Affordable Power Rider.

i. CAC Case-in-Chief. CAC witness Inskeep discussed what he viewed as an unaffordability crisis in Indiana. He testified that nationally, millions of American families cannot afford their utility energy bills and are forgoing basic necessities to pay high utility bills. He stated that electric bill unaffordability is negatively impacting the Company's customers specifically. Mr. Inskeep testified that unpaid Duke residential customer accounts surpassed $34 million in January 2024 compared to $21.1 million in January 2023, and $4.4 million in January 2022; the number of residential accounts converted to uncollectible expenses has increased steadily each year since 2020 (28,000 accounts), rising from approximately 35,000 accounts in 2021 to 52,000 accounts in 2023; the number of Low Income Home Energy Assistance Program accounts converted to uncollectible expenses rose from 400-600 customers per year in 2020–2022 to nearly 4,800 accounts in 2023; and, the number of defaulted payment agreements has increased from about 42,000 in 2020 to 69,000 in 2023. He opined that the Company's existing and proposed programs meant to address unaffordable bills are insufficient for comprehensively decreasing high bill costs to an affordable level on a sustainable basis for many households. He stated participation in these programs is low and the Low Income Home Energy Assistance Program alone is insufficient at addressing unaffordability challenges faced by Duke electric customers. Mr. Inskeep testified that such challenges can lead customers to undertake risky coping strategies to pay all or part of their utility bill which can ultimately fail and result in being charged late fees, served disconnection notices, and eventually disconnected from utility service. He stated this can create health and safety issues especially in extreme heat situations where Duke will only suspend disconnections if the temperature is higher than 105 degrees or lower than 25 degrees Fahrenheit. He stated unaffordable rates can lead to eviction, or even have children removed from the disconnected home and unaffordable bills are therefore a grave concern for ratepayers and their families, as well as for broader social health and welfare.

To address this unaffordability crisis, Mr. Inskeep recommended the Company implement an Affordable Power Rider. The Affordable Power Rider would be a new rider for Duke residential customers that provides a tiered discount mirroring the current Universal Service Fund Rider discount percentages used by CenterPoint South Gas (15% at Tier 1, 26% at Tier 2, and 32% at Tier 3), with cost recovered through a per-kWh charged assessed identically on all retail sales. Mr. Inskeep testifies that this rider aims to be consistent with the Five Pillars and Indiana policy on affordability and to make electric service more affordable to low-income residential customers. Mr. Inskeep also recommended establishing a 12-month disconnection moratorium to allow time for Duke to establish and implement additional affordability measures, including the Residential Affordable Power Rider, in order to provide immediate direct bill assistance to some of the Company's most vulnerable low-income households.

ii. Industrial Group Cross-Answering Testimony. Mr. Collins recommended that the Commission reject CAC witness Inskeep's proposed Affordable Power Rider. Mr. Collins testified that Duke already has numerous riders which have not decreased the frequency or size of rate increases. He testified that the Affordable Power Rider would by its nature create a new subsidy for the residential class. Mr. Collins asserted that the proposed rider would make Duke's industrial rates even less competitive, would violate the affordability pillar with respect to industrial rates, and is contrary to the goal of minimizing and eliminating subsidies in electric rates so as to achieve cost-based price signals.

iii. Duke Rebuttal. Mr. Colley provided an overview of Duke's programs to assist its customers with their affordability challenges. He broadly grouped these offerings into four categories—customer assistance funds, energy efficiency and weatherization, bill management options, and income qualified programs. He asserted that Duke did not receive sufficient information from the CAC to evaluate program.

iv. Additional Evidence Received at Hearing. Mr. Colley reiterated this testimony that Duke did not have sufficient information to evaluate the proposed Affordable Power Rider. Mr. Colley also stated that the "affordability ecosystem" he described on rebuttal does not have unlimited program funding, does not remove a customer's payment obligation to the Company, and does not address the affordability of individual monthly bills.

v. Commission Discussion and Findings. The evidence establishes that Duke has implemented a number of programs in an effort to address affordability. We find insufficient evidence to support issuing a directive to Duke to implement the proposed Affordable Power Rider program. As such, we deny the CAC's request.

D. Service Adequacy and Economic Development.

i. RRPOA Case-in-Chief. Mr. Hildenbrand testified that River Ridge has repeatedly demonstrated and communicated to Duke a need for more energy at the River Ridge Commerce Center ("RRCC"), and Duke's decision not to fast-track River Ridge's service needs is unacceptable. Mr. Hildenbrand testified that it is particularly inappropriate for Duke to be awarded a rate increase when Duke is not providing adequate energy service to River Ridge. Mr. Hildenbrand recommended the Commission deny Duke's request for a rate increase unless and until Duke provides adequate service to meet the future energy needs of the RRCC. He further recommended the Commission disallow any recovery of costs by Duke associated with transmission and distribution projects at the RRCC that have not yet commenced. Mr. Hildenbrand also recommended the Commission order Duke, as a condition of any rate relief, to prioritize and immediately commence work on the capacity and line upgrade projects at the RRCC discussed in his confidential testimony. Finally, he recommended the Commission adopt the recommendations of RRPOA witness Josh Staten.

Mr. Staten requested the Commission require Duke to create a standard tariff offering mirroring the structure of Duke's contract with Blocke and promote that offering to qualifying users as a standard part of its incentive negotiation process; requested that the Commission order Duke to expedite and prioritize transmission and distribution projects necessary to serve new load within the RRCC and allow for competitive providers to build transmission and distribution facilities if they are able to complete construction more quickly than Duke; and explained why the Commission should require Duke to prioritize and commence projects necessary for River Ridge to offer sufficient energy to businesses considering locating at the RRCC.

Mr. Staten testified that Blocke has recently committed to locate or expand at the RRCC, which combined with other companies that also have commitments in place, will consume most of the current available electric capacity. He said he is concerned that Duke currently may not be able to serve any additional businesses at the RRCC with required electric loads as low as 5MW without a delay of several years, so, absent an alternative avenue for securing necessary electric service, River Ridge may have to indefinitely pause efforts to attract investment from new or expanding companies.

Mr. Staten testified that electric rates and the ability of a utility to meet the required electric capacity are often the difference between winning or losing a project. He testified a recent study commissioned by River Ridge noted that that one of the RRCC's primary disadvantages was non-competitive electric rates. Mr. Staten stated that the study concluded that if the RRCC offered electric rates comparable to that of the other evaluated sites, then the RRCC would be a low-cost and high-quality option.

Mr. Staten testified that it is not uncommon for 100 or more sites to be submitted for one single project; creating a scenario in which companies and their consultants are engaged more in a "site elimination" than a "site selection" process, meaning it would be possible for a company to opt for another location with more competitive electric rates, rather than choosing the RRCC. He noted Duke's current rates put the RRC at a competitive disadvantage against other sites, especially in the southeast United States and even if a company elected to proceed with locating at the RRCC, it would likely reduce the overall project scope, lowering capital investment, tax revenue, labor investment, and jobs due to the electric rates.

Mr. Staten testified that Duke recently entered into a special contract to serve Blocke, which is now located at the RRCC. He stated that Blocke intends to build an $800 million data center resulting in over 100 high paying jobs. Mr. Staten noted that although the contract is confidential, the Commission Order approving the contract indicates Duke agreed to supply a percentage of Blocke's load with renewable energy from renewable resources purchased through renewable PPAs under a specific arrangement for Duke's recovery of its costs. Mr. Staten testified that the special contract requires Duke to use the PPAs to meet Blocke's hourly energy needs and provides that in hours when renewable energy from the PPAs is insufficient to meet Blocke's needs, the additional energy will be supplied through the MISO energy market.

Mr. Staten testified that River Ridge and Duke engaged in a series of emails between July 8, 2024 and July 10, 2024, revealing Duke Energy's remaining capacity to serve additional load at River Ridge and the protracted four to five year timeline for Duke to provide more. Mr. Staten testified that, with no accountability measures in place to prevent Duke from extending this timeline. Mr. Staten testified that based upon Duke's current plans for upgrades within the RRCC, prior to 2029, Duke could not provide service to a prospective company wanting to locate at the RRCC, or any existing company looking to expand within the RRCC, unless the company could make unusual arrangements. Mr. Staten stated that, because one of the factors for prospective businesses interested in RRCC is their "speed to market," Duke's prolonged timelines for providing additional service are harmful to the RRCC. He noted that River Ridge has proactively set aside 45-acres on the north side of the RRCC for Duke, but Duke has stated that it does not intend to commence work on a project to provide greater capacity absent new commitment(s) from future user(s).He testified that Duke frequently picks the winners and losers through its rate structure, incentive packages, and where it prioritizes needed infrastructure improvements, including the build out of transmission and distribution facilities and increases in system capacity.

Mr. Staten agreed with Mr. Hildenbrand that the Commission should consider denying Duke's request for a rate increase. He stated that it is fundamentally unfair for customers to pay even higher rates when Duke is unable to provide adequate service to meet the load within its territory. He also testified that it is unfair to River Ridge, prospective customers, and the citizens of Clark County to sit idly by for potentially five or more years with very limited development, investment, or new job creation given that Duke has a monopoly to serve within its service territory. Mr. Staten recommended the Commission require Duke to amend its tariffs to explicitly allow prospective customers to enter into special contracts like the Blocke contract in which the customer can access sufficient power through the market if Duke is unable to meet its service needs. Mr. Staten stated that while such a tariff would connect new load to power generation, the customer is dependent upon Duke to provide adequate transmission and distribution facilities. Thus, he testified that the Commission should order Duke to expedite and prioritize transmission and distribution projects that are necessary to serve new load, or allow for competitive providers to build transmission and distribution facilities if they are able to complete construction more quickly than Duke. Mr. Staten testified that, if necessary, the Commission could require the prospective customer to contribute an upfront partial payment for the transmission or distribution project necessary to serve the new load.

Mr. Staten recommended that Duke offer a tariff for customers with defined eligibility characteristics that includes a threshold of proposed power usage, significant investment, and/or new job creation. He recommended the tariff offering allow qualified customers to access energy from the MISO market when Duke is unable or unwilling to supply the energy needed to serve the customer. He also recommended the offering allow, but not require, the customer to be supplied using renewable energy and use a construct that allows Duke to recover its reasonable costs without burdening other ratepayers for the costs of the arrangement.

Mr. Staten testified that it is most appropriate for Duke to amend its tariff as part of a rate case because the Commission and parties should consider what, if any, rate impacts will result from such a tariff offering. He also stated that under Duke's current economic development tariff (to which Duke proposes no changes in this proceeding), Duke enjoys wide discretion to pick winners and losers who receive the arrangement that Blocke negotiated. Mr. Staten noted that, unlike the publicly available information on incentives River Ridge offers to prospective customers, the details of the Blocke arrangement are not publicly available, so a general tariff offering that allows a defined class of customers to access the energy market like Blocke puts large scale customers on more equal footing and creates public awareness of the market access option. Mr. Staten testified that such a tariff offering will create a tool that could help remedy the energy crisis that Duke has created.

Ultimately, Mr. Staten recommended the Commission adopt Mr. Hildenbrand's recommendations; deny Duke's requested rate increase absent a showing by Duke that it will serve additional load in the amounts and on the timeframes requested by new customers at the RRCC; require Duke to create a general tariff offering that allows a defined class of customers to access the energy market similar to Duke's arrangement with Blocke; order Duke to expedite and prioritize transmission and distribution improvement projects necessary to serve new load and allow for competitive providers to build transmission and distribution facilities if they can complete construction more quickly than Duke, including the addition of specific capacity within 18-24 months and expedited upgrades to the system.

ii. **Rolls Royce Case-in-Chief.** Mr. White expressed appreciation that Duke included transmission upgrades for Rolls-Royce in its 6-Year Electric Plan ("TDSIC 2.0") that was approved in 2022 by the Commission in Cause No. 45647. Mr. White expressed concern that based on Duke's TDSIC 2.0, it appears that Duke is not in a position to respond quickly enough to provide Rolls-Royce with anticipated needed power in the future.

Mr. White testified that if Duke is unable to serve additional load at Rolls-Royce or the Discovery Park District ("Discovery Park") generally, the Commission should consider denying Duke's request for a rate increase. He testified that it is fundamentally unfair for customers to pay even higher rates if Duke is unable to provide adequate service to meet the current and growing load within its territory. He testified that if Duke confirms that it is unable to serve additional load at Discovery Park, it is unfair to Rolls-Royce and the other economic development customers to wait until Duke upgrades its system. Mr. White testified that the Commission should order Duke to expedite and prioritize transmission and distribution projects necessary to serve new load at Discovery Park because there are substantial enough economic development activities currently in process to justify the investment in the infrastructure to support current customers and draw new economic opportunities to the area.

Mr. White testified that Rolls-Royce is concerned with the price of electricity, as it has a direct impact to available cash and profit to reinvest in further infrastructure and talent needs in the business. He stated that a key issue for Rolls-Royce is Duke's pricing structure and application of its rates. He testified that the unique load profile for aerospace engine testing is a key factor in site selection for investment across the industry and noted that the basic rate structure applied for a 'normal' business with sustained and normal loads is not fair or reasonable for the aerospace sector – a sector of stated focused growth from the Indiana Economic Development Corporation.

Mr. White also testified regarding Rolls-Royce's frustration with obtaining a special contract with Duke. He noted that Rolls-Royce has a special contract with AES Indiana for its

Indianapolis engine testing facility because of its unique load profile and Rolls-Royce's willingness to negotiate curtailment conditions. He stated that thus far, Duke has been reluctant to consider any special contract with Rolls-Royce even though it offers special contracts to other businesses for economic development projects. Mr. White testified that Duke has special contracts with Blocke, approved by the Commission in *Duke Energy Indiana, LLC*, Cause No. 45975 (IURC April 24, 2024), and with Nucor, in *Duke Energy Indiana, LLC*, Cause No. 45934 (IURC May 22, 2024). Mr. White testified that those projects are no more important than Rolls-Royce's project, and Duke has already stated that Rolls-Royce's project is a TED project for TDSIC purposes. Mr. White testified that Rolls-Royce's economic development project has more benefit to the community, as it directly impacts national defense and homeland security, rather than only the interests of a private business. Mr. White recommended that Duke create a tariff offering for customers with defined eligibility characteristics that includes a threshold of benefit to the community, significant investment, and/or new job creation. He testified that under Duke's current economic development tariff (to which Duke proposes no changes in this proceeding), Duke enjoys wide discretion to pick winners and losers who receive the benefits of special contracts. He noted that the details of existing special contracts are not publicly available, so a general tariff offering for a defined class of customers would put large customers on more equal footing and create awareness of the special contract option. Ultimately, Mr. White recommended the Commission deny Duke's requested rate increase; order Duke to expedite and prioritize transmission and distribution projects that are necessary to serve new load for projects already announced at Discovery Park; and require Duke to create a general tariff offering that allows a defined class of economic development customers, such as the aerospace sector, to be eligible for special contracts similar to Duke's arrangements with Blocke and Nucor.

iii. **<u>Duke Rebuttal</u>.** On rebuttal, Company witness Pinegar testified the investments these parties are requesting Duke be required to expedite are (1) to attract speculative economic development and (2) will cause upward pressure on rates. He testified that having a shovel ready development may help the RRCC market its site and encourage quicker economic development to the Clark County area; however, the Company must retain the flexibility to serve more committed projects, large and small, in all corners of its service territory. Mr. Pinegar testified that the Company has a proven track record and will continue to build on that success by working closely with its many partners, such as RRPOA, as well as any prospect committed to Duke's service territory. He stated Duke remains committed to working with River Ridge and other stakeholders to continue fostering economic growth and development throughout its entire 69-county service area.

Mr. Pinegar further testified that to do as RRPOA and Rolls-Royce suggests runs afoul of the Five Pillars. He testified it would compromise affordability as unnecessary costs could be imposed on all customers through the subsidization of potentially unused projects, resulting in stranded assets. He further testified it would undermine reliability and resiliency by diverting resources from projects with more verifiable needs.

iv. **<u>Commission Discussion and Findings</u>.** Ind. Code § 8-1-2-4 requires electric utilities "to furnish reasonably adequate service and facilities." RRPOA and Rolls-Royce assert that the Commission should direct Duke to expedite and prioritize transmission and distribution projects that are necessary to serve new load at particular sites. We disagree.

Duke's obligation under Ind. Code § 8-1-2-4 includes balancing capital investments to support its customers' efforts for economic growth, with the need to keep rates affordable for its 900,000 customers throughout its entire 69-county service territory. The evidence established that Duke is already engaging with RRPOA and Rolls-Royce and providing upgrades in their respective geographic areas. For example, in 2022, in Cause No. 45647, Duke received Commission approval to provide transmission upgrades for Rolls-Royce and in Cause No. 45647 S1 the Commission approved a TED project at the RRCC. The evidence also establishes that Duke's economic development team continues to prioritize economic development throughout the state; in 2023, Duke helped create over 4,500 jobs and generate $6.4 billion in capital investment throughout its service territory. We will not "pick favorites" and order Duke to prioritize or expedite investment that benefits only certain entities, such as RRPOA and Rolls-Royce. We find insufficient evidence to support a directive mandating Duke to expedite and prioritize transmission and distribution projects as requested by RRPOA and Rolls-Royce.

Further, regarding the parties' request for a special contract, Indiana law does not mandate the use of special contracts, and we agree with Mr. Pinegar that each special contract case requires careful consideration of regulatory, financial, and operational implications. We also decline to require Duke to create RRPOA and Rolls-Royce's proposed tariff. Special contracts are specifically authorized by Indiana statute, Ind. Code § 8-1-2-24. The statute allows for certain arrangements that are "practical and advantageous" to the involved parties with Commission approval. We agree with Company witness Flick that to standardize special contracts into a tariff offering would run counter to the intent of Ind. Code § 8-1-2-24, eliminate the Commission's individualized review of special contracts, and reduce the flexibility needed to tailor agreements to specific customer and Company needs. As Mr. Flick explained, special contracts are intended to be extremely flexible allowing for customized service agreements for large customers with unique service characteristics and the ability and willingness to assume risk. We agree that these factors argue against broad utilization via a standardized tariff offering.

The Commission operates within an established framework for each special contract case to ensure that all customers benefit from the load the contract helps the Company secure. While Ind. Code § 8-1-2-24 provides a statutory mechanism for utilities to enter into special contracts, it does not require that utilities do so. Ultimately, if the Legislature had intended for these types of arrangements to be broadly available, we assume it would have done so. Further, the record demonstrates the Company offers an economic development rider, Rider 58, which is designed to provide incentives for new or expanding load funded with shareholder dollars. This Rider allows the Company to work collaboratively with customers while also supporting economic growth.

For these reasons, we reject the intervenors' recommendations with respect to these economic development issues, and we encourage the parties to continue working together collaboratively to support and foster economic development in the State of Indiana.

17. Confidentiality. On April 4, 2024, and July 19, 2024, Duke filed Motions for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which were supported by affidavits asserting that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. On July 11, 2024, RRPOA also filed a Motion for Confidential Treatment in this Cause. In Docket Entries dated April 18, 2024, and August 21, 2024, the Presiding Officers determined the information should be held confidential on a preliminary basis, after which the information was submitted under seal. After review of the information and consideration of the affidavits, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held as confidential and protected from public access and disclosure by the Commission.

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

1. Duke Energy Indiana is authorized to place into effect base rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual increase to its rates and charges of $395,691,000 (excluding changes in items remaining in riders). Said rates are calculated to produce total jurisdictional electric operating revenues of $3,315,159,000 and, on the basis of annual jurisdictional electric operating expenses of $2,467,698,000 will result in annual jurisdictional electric utility operating income of $772,635,000. The Company is authorized to file with the Commission a new schedule of rates and charges which will properly reflect, establish and provide the operating revenues herein authorized. Said schedule of rates and charges should be in accordance with this Order, including implementation of this rate increase in two steps as approved herein.[19]

2. Duke Energy Indiana shall file with the Energy Division of this Commission, appropriate tariffs using the rate design criteria specified in this Order, including the rates and charges authorized herein for Step 1 and Step 2. Rates for Step 1 and Step 2 shall be implemented and shall take effect pursuant to the process we have approved in Finding Paragraph 13A. The rates and charges for Steps 1 and 2 shall be implemented upon approval of the filed tariffs on a service-rendered basis.

3. Commencing with the first of the month following the effective date of updated base rates, Petitioner is authorized to place into effect the depreciation rates approved in this Order.

4. Duke Energy Indiana is authorized to implement the changes to various Rate Adjustment Riders as approved in this Order, specifically changes to Riders 60, 62, 65, 66, 67, 68, 70, 72, 73 and 74, all as determined in this Order.

5. Duke Energy Indiana is authorized to implement the rate design proposals and tariff changes as approved in this Order.

6. Duke Energy Indiana is authorized to utilize a base cost of fuel of 34.378 mills per kWh and a net operating income of $772,635,000 in its FAC proceedings. For purposes of computing the authorized net operating income for Indiana Code § 8-1-2-42(d)(3), the increased

[19] The numbers are subject to refinement pending the division reviewed and approved order directed compliance filings of Ordering Paragraph 2.

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 is granted a 35-day period to review Petitioner's FAC applications and to file OUCC testimony in such proceedings.

7. The information submitted under seal in this Cause pursuant to Petitioner's and RRPOA'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.

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

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

APPROVED: JAN 29 2025

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

Dana Kosco Digitally signed by Dana Kosco
Date: 2025.01.29 10:12:34
-05'00'

Dana Kosco
Secretary to the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A MULTI-STEP RATE IMPLEMENTATION OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE, AND APPROVAL OF REGULATORY ASSET TREATMENT UPON RETIREMENT OF THE COMPANY'S LAST COAL-FIRED STEAM GENERATION PLANT; (4) APPROVAL OF AN ADJUSTMENT TO THE COMPANY'S FAC RIDER TO TRACK COAL INVENTORY BALANCES; AND (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO: (A) DEFER TO A REGULATORY ASSET EXPENSES ASSOCIATED WITH THE EDWARDSPORT CARBON CAPTURE AND SEQUESTRATION STUDY, (B) DEFER TO A REGULATORY ASSET COSTS INCURRED TO ACHIEVE ORGANIZATIONAL SAVINGS, AND (C) DEFER TO A REGULATORY ASSET OR LIABILITY, AS APPLICABLE, ALL CALCULATED INCOME TAX DIFFERENCES RESULTING FROM FUTURE CHANGES IN INCOME TAX RATES	)	**CAUSE NO. 46038** **APPROVED: JAN 29 2025**

CONCURRING OPINION OF COMMISSIONER SARAH E. FREEMAN AND COMMISSIONER DAVID E. VELETA

We write separately to concur in result with respect to the denial of Petitioner's DC Fast Charging request in Section 9.N.ii. We agree with the majority that there is insufficient evidence in the record to support the inclusion of the costs at issue. However, we disagree with the majority's interpretation of Ind. Code. § 8-1-2-1.3 to make such a bright line distinction between owning and operating EV supply equipment for use by the public and being a retail rate regulated public utility. The pertinent statutory language in Section 1.3(d) provides that "[a] person . . . that . . . owns, operates, or leases EV supply equipment . . . and . . . makes the EV supply equipment available for use by the public for compensation . . . is not a public utility solely by reason of engaging in [either] activity[.]" A literal reading of this subsection implies (at least partially) the opposite—that a public utility, which includes retail rate regulated public utilities, may indeed own and operate EV supply equipment for use by the public, independent of its regulatory status, under the appropriate circumstances. This proceeding and this record, however, do not present these circumstances and, for these reasons, we respectfully concur in result.

We also are concerned with the majority's fixed view of the utility's role in the fast charging space. As electrification of the transportation sector continues to grow, there may come a point during the buildout by the private sector of public-facing electric vehicle charging infrastructure in which portions of Duke's territory are not adequately covered. As a result of these gaps in the availability of electric vehicle charging infrastructure, Duke may have a role in providing electric vehicle charging in areas that the private sector does not want to serve as long as Duke can provide evidence of material unmet demand in supporting a public interest determination.