FILED
April 15, 2020
INDIANA UTILITY
REGULATORY COMMISSION

DIRECT TESTIMONY OF BRIAN P. DAVEY
VICE PRESIDENT, RATES AND REGULATORY STRATEGY, INDIANA
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 45253 S1 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian P. Davey, and my business address is 1000 East Main Street, Plainfield, Indiana.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana LLC ("Duke Energy Indiana," "Petitioner" or "Company") as Vice President, Rates and Regulatory Strategy, Indiana.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT, RATES & REGULATORY STRATEGY.

A. As Vice President, Rates and Regulatory Strategy, Indiana, I am responsible for regulated rate matters including the Company's various rider filings for Duke Energy Indiana.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor's of Science Degree in Accounting from Indiana University of Indianapolis. I joined Duke Energy Indiana (formerly Public Service Company of Indiana, Inc., a predecessor of the Company) as a staff accountant. I have held various positions in the Rate Department, Corporate Accounting and Financial Forecasting. In 1994, I was promoted to Cinergy's Financial Forecast manager and subsequently held manager and director positions in the Commercial Business Unit with Accounting, Budgeting and Forecasting responsibilities. In 2003, I was promoted to Assistant Controller. In 2005, I became General Manager of Budgets and Forecasts. In 2006, I became Duke Energy's General Manager of Financial Planning for U.S. Franchised Electric and Gas. In late 2006, my responsibilities were specifically related to the Midwest jurisdictions of U.S. Franchised Electric and Gas. In 2009, I assumed my current responsibilities. I am a Certified Public Accountant and a member of the Indiana CPA Society.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to explain the Company's proposed accounting and ratemaking treatment for certain estimated coal ash management and closure costs of compliance with: 1) the U.S. Environmental Protection Agency's ("EPA") Coal Combustion Residuals ("CCR") rule ("CCR Rule") promulgated under the Resource Conservation and Recovery Act ("RCRA"); and 2) Indiana Department of Environmental Management ("IDEM") solid waste rules also promulgated under RCRA. The coal ash management and closure compliance projects ("Projects") proposed by Duke Energy Indiana in this proceeding comprise the compliance plan ("Coal Ash Compliance Plan" or "Plan") for which a Certificate of Public Convenience and Necessity ("CPCN") and cost recovery pursuant to Indiana Code 8-1-8.4 ("Federal Mandate Statute") is sought to be approved in this proceeding.

I will discuss: 1) the Company's proposal to recover the retail jurisdictional portion of the Plan costs, including the use of the Company's existing Standard Contract Rider No. 62 – Environmental Compliance Adjustment ("Rider 62"), with revisions as proposed and supported by the testimony of Company witness Ms. Christa L. Graft in Cause No. 45253, as the periodic rate adjustment mechanism for timely recovery; and 2) the Company's request for Commission approval of the use of deferral accounting for the Plan costs, including the accrual of financing costs on an interim basis, to the extent the costs are not yet included in retail rates, and until such costs are reflected in Duke Energy Indiana's retail rates. I will also provide an estimate of the jurisdictional rate impacts of the Company's proposed compliance Plan.

In addition, I will describe the Company's accounting deferral request related to the estimated additional future coal ash management and closure costs required for additional CCR and IDEM projects that are not currently included in the Plan presented for CPCN approval in this sub-docket.

Q. PLEASE EXPLAIN WHICH COAL ASH MANAGEMENT AND CLOSURE COSTS ARE THE SUBJECT OF THIS SUB-DOCKET PROCEEDING?

A. In Cause No. 45253 the Company proposed recovery in base rates for a regulatory asset comprised of coal ash management and closure costs which had been incurred through December 2018, 2019 and 2020 forecasted costs related to certain IDEM projects with approved closure plans at the time of the case-in-chief filing, and financing costs on the costs included that are forecasted to be incurred by the end of the calendar year 2020 test period ("Past Costs").[1] The Company also requested deferral accounting treatment, including accrual of financing costs, for future recovery and issuance of a Certificate of

[1] The IDEM projects for which 2019 and 2020 forecasted costs of $8.6 million were included in the regulatory asset as part of the Past Costs in the pending base rate case include the Gibson East Ash Pond and Dresser Station closure projects.

Public Convenience and Necessity under the Federal Mandate Statute for certain additional forecasted coal ash management and closure costs to be incurred ("Future Costs"), until such costs were included in retail rates in a future proceeding. The Commission's December 5, 2019 Docket Entry in Cause No. 45253 created this sub-docket proceeding to address the request for a CPCN under Indiana Code 8-1-8.4 for estimated future federally mandated ash pond closure costs.

As such, the Company has included in this proceeding the estimated coal ash management and closure costs not included in the forecasted December 31, 2020 regulatory asset balance of Past Costs being considered for recovery in Cause No. 45253. The estimates included in Cause No. 45253 testimony for Future Costs have been updated for purposes of this sub-docket proceeding to reflect the now current status of state closure plan approvals and approved or revised closure protocols and to reflect the latest timing and cost estimates for closure projects.

The Company has limited its CPCN and cost recovery request in this sub-docket to the portion of estimated future federally mandated Project costs for which the Company's closure plans have been approved by IDEM as of April 1, 2020, along with certain ongoing post-closure maintenance and non-basin closure costs. The coal ash management and closure costs have been estimated through 2028 for purposes of this proceeding and determining a rate impact of the proposed compliance Plan, although, as discussed in the Testimony of Mr. Owen R. Schwartz, these activities (and their attendant costs) will be required for thirty years following basin closure. The resulting federally mandated costs and Projects are being presented in the proposed compliance Plan, for which the Company is requesting approval in this sub-docket proceeding. The Testimony of Messrs. Schwartz and Timothy J. Thiemann further explain and support the mandated activities and Projects included in the Plan, the costs I have included in the rate impacts for the Plan, and the Company's request for CPCN issuance under the Federal Mandate Statute for the Plan.

In addition, the Company is presenting high level estimates in the testimony of Mr. Thiemann related to the portion of estimated future federally mandated costs for which closure plans have not yet been approved by IDEM, as well as post closure costs for 2029 and after and will request accounting deferral treatment, with financing costs, for such costs, as I will discuss later in my testimony.

II. PROPOSED ACCOUNTING AND RATEMAKING FOR COMPLIANCE PLAN COSTS

Q. PLEASE PROVIDE AN OVERVIEW OF COST RECOVERY FOR FEDERALLY MANDATED REQUIREMENTS UNDER INDIANA CODE 8-1-8.4.

A. Indiana Code § 8-1-8.4-7(c) provides for recovery of Commission-approved federally mandated costs that an energy utility incurs in connection with an approved compliance project undertaken as a result of federally mandated requirements. Indiana Code § 8-1-8.4-7(c)(1) provides that "Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs."[2] Pursuant to Indiana Code § 8-1-8.4-4, federally mandated costs "means costs that an

[2] Indiana Code § 8-1-8.4-7(c)(1) also provides that the Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of Indiana Code § 8-1-2-42(d)(3) and Indiana Code § 8-1-2-42(g)(3), also referred to generally as the fuel clause earnings test.

energy utility incurs in connection with a compliance project, including capital, operating, maintenance, depreciation, tax, or financing costs." Indiana Code § 8-1-8.4-7(c)(2) provides that the remaining "[t]wenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission." Indiana Code § 8-1-8.4-7(c)(3) further provides that "[a]ctual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission."

Q. PLEASE PROVIDE AN OVERVIEW OF THE FEDERALLY MANDATED COSTS THAT WILL BE INCURRED IN CONNECTION WITH ITS PROPOSED COMPLIANCE PROJECTS.

A. The federally mandated costs included in the Plan proposed in this proceeding include:

- Costs associated with certain coal ash management closure Projects incurred or to be incurred at the Company's Cayuga, Gibson, Gallagher and Noblesville generating stations and at the Company's retired Wabash River and Dresser generating stations, described in more detail by Mr. Thiemann. As explained in the testimony of Company witnesses Ms. Diana L. Douglas and Ms. Melissa B. Abernathy in Cause No. 45253, expenditures associated with coal ash management and closure projects like these that are federally mandated are recorded on the balance sheet as a regulatory asset under the Company's required accounting under Generally Accepted Accounting Principles ("GAAP") for Asset Retirement Obligations ("ARO"). However, in general, if the costs weren't considered a legal obligation under ARO accounting, they would have been accounted for as a cost of removal in a plant account.

- Additional costs associated with the Projects include amortization of the closure costs included in the regulatory asset, ongoing post-closure maintenance and non-basin closure costs, taxes and financing costs.

Q. WHAT SPECIFIC APPROVAL ARE YOU ASKING FROM THE COMMISSION RELATED TO RATEMAKING IN THIS FILING?

A. As explained in the testimony of Mr. Schwartz, the EPA's CCR Rule and IDEM's solid waste management rules are both authorized by the federal RCRA and, as such meet the definition under Indiana Code 8-1-8.4 of a federally mandated requirement. As explained in the testimony of Mr. Thiemann, the Plan consists of compliance projects undertaken for direct or indirect compliance with the federally mandated requirements. The Company is therefore requesting authority from the Commission to recover the retail jurisdictional portion of the federally mandated costs of the Plan pursuant to Indiana Code § 8-1-8.4-7. Specifically, the Company is requesting:

1. Approval from the Commission of the use of its existing Rider 62, with revisions as proposed and supported by the testimony of Company witness Ms. Christa L. Graft in Cause No. 45253, for the timely recovery of 80% of the retail jurisdictional portion of

Plan costs including capital, operating, maintenance, depreciation, tax, or financing costs. The Commission has previously approved the use of the Company's Rider 62 (and Rider 71, which is being combined with Rider 62 upon approval by the Commission in Cause No. 45253) to recover the retail jurisdictional portion of the costs for certain clean air environmental compliance projects and most recently in Cause No. 44765 for other federally mandated compliance projects under the CCR Rule at its generating facilities.

2. Authority from the Commission to use a regulatory asset (using the Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations ("CFR") account 182.3) to accrue the 80% of the retail jurisdictional portion of the federally mandated costs of the Plan that are eligible for rider recovery until they can be included in retail rates.

3. Authority from the Commission to accrue financing costs on the 80% of retail jurisdictional portion of the expenditures under the Plan at rates equal to Duke Energy Indiana's most recently approved weighted average cost of capital ("WACC") – using the equity return approved by the Commission in the Company's most recent retail base electric rate case, until the costs are included in retail rates.

4. Authority from the Commission to accrue a regulatory asset (using FERC Code of Federal Regulations account 182.3) for the retail jurisdictional portion of the 20% of the federally mandated costs that are not eligible for timely rider recovery per the Federal Mandate Statute and for authority to accrue financing costs at rates equal to

Duke Energy Indiana's most recently approved WACC – using the equity return approved by the Commission in the Company's most recent retail base electric rate case– on the deferred 20% portion of the federally mandated costs until such costs are fully reflected in Duke Energy Indiana's retail base rates after a general retail rate case.

5. Authority for deferral accounting treatment, consistent with the treatment approved for the 20% portion of the federally mandated costs, for the retail jurisdictional portion of any such costs which exceed the estimate by more than 25%, until such time as the costs may be reviewed and included in base rates in a retail rate case, consistent with the Federal Mandate Statute requirements.

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING WITH RESPECT TO CONSTRUCTION WORK IN PROGRESS ("CWIP") RATEMAKING TREATMENT?

A. Upon Commission approval of the compliance projects included in this proceeding as federally mandated projects, Duke Energy Indiana is proposing to commence CWIP ratemaking treatment (*i.e.*, recovery of cash return on investment expenditures via a Rider rather than continued accrual of financing costs on the expenditures) via Rider 62 in the next practicable filing (anticipated to be Cause No. 42061 - ECR 35 to be filed in the spring of 2021) for the retail jurisdictional portion of the costs incurred as of the cut-off date for the rider for the closure Plan Projects incremental to amounts included in base rates, with accrued financing costs. Amounts included for return calculation purposes will reflect the reduction of accumulated amortization amounts included in Rider 62 rates as of each Rider 62 cut-off date for expenditures. Consistent with the Commission's prior precedent, the Company will continue this ratemaking treatment until the Commission determines these projects are used and useful and included in a proceeding that involves the establishment of the Company's base retail electric rates and charges.

Q. WHAT ARE FINANCING COSTS?

A. Financing costs are one of the types of costs specifically defined under Indiana Code § 8-1-8.4-4 as a recoverable federally mandated cost. Generally, financing costs are accrued on capital construction projects in the form of allowance for funds used during construction ("AFUDC") (to the extent the costs are not already placed into rider rates for CWIP ratemaking recovery) until they are placed in service, at which time AFUDC accrual stops and post-in-service carrying cost accrual begins. As recognized in the Federal Mandate Statute and in prior Commission approvals for Duke Energy Indiana in Cause No. 44765 and in various subsequent Cause No. 42061 rider filings including the compliance plan costs approved in Cause No. 44765, financing costs are not only incurred and recoverable under the Federal Mandate Statute on capital construction projects which have specific in-service dates, but also on other federally mandated costs which are not yet included in a rider for timely recovery. Accordingly, financing costs will be accrued on the coal ash closure costs included in the Company's Plan (deferred in the regulatory asset due to the Company's ARO accounting), as well as Project-related post closure maintenance expenditures, until the costs are recovered via rates.

Q. TO WHAT EXTENT WILL FINANCING COSTS BE ACCRUED ON THE 80% OF THE PROJECT COSTS INCLUDABLE IN RIDER 62?

A. The Company proposes to accrue in a regulatory asset account the financing costs on any portion of the retail jurisdictional portion of the 80% of the Project expenditures included in this proceeding that are not yet earning a CWIP ratemaking return in Rider 62 and to continue the accrual, including on previously computed financing cost amounts, until such expenditures and accrued financing costs are recovered in the Company's retail rates (via Rider 62 or retail base rates). For GAAP accounting and reporting purposes, the Company will reflect in its Income Statement the deferral of incurred interest expense on the full amount of expenditures incurred during the cost deferral period and will then recognize in earnings the remaining cost of capital amounts on a pro rata basis as such amounts are included in billings to customers.

Q. DOES THE COMPANY HAVE CONTROLS IN PLACE TO ENSURE FINANCING COSTS ARE NOT ACCRUED ON THE SAME FEDERALLY MANDATED COSTS ONCE THEY ARE INCLUDED IN RIDER 62?

A. Yes, the Company has existing processes and controls in place for all its capital riders, including Rider 62, to stop the accrual of financing costs in the regulatory asset once the costs are included in rider rates to prevent the potential double-recovery of financing costs.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S RIDER 62, WITH PROPOSED POST-BASE RATE CASE MODIFICATIONS.

A. In addition to CWIP ratemaking return, Rider 62 provides for the recovery of related costs, including depreciation, amortization and other expenditures (recovery is currently related to clean energy and certain federally mandated projects under the CCR rule, as well as recovery of plan development costs and post-in-service carrying or other financing costs associated with the projects.) Rider 62 is updated on a semi-annual basis using a June 30 and December 31 cut-off period for incurred expenditures, using a forecast for the estimated costs of operating expenditures. The estimated costs are subsequently reconciled to actual costs, and any difference between actual amounts incurred for both return and operating expenditures and amounts collected from customers is subsequently collected from or credited to customers, as appropriate. The addition of return to the reconciliation process is one of the modifications proposed in Cause No. 45253.

Q. WHAT IS THE COMPANY REQUESTING IN THIS PROCEEDING RELATED TO ITS RIDER 62 FOR PLAN COSTS OTHER THAN RETURN ON INVESTMENT?

A. Upon Commission approval of the compliance projects included in this proceeding as federally mandated costs, Duke Energy Indiana is proposing to recover via Rider 62 80% of the retail jurisdictional portion of the other federally mandated operating expenditures included in the approved Plan, including amortization of expenditures included in regulatory assets (including financing costs accrued), taxes, and post-closure maintenance expenditures. As discussed previously, the Company also requests that the Commission approve the deferral of the expenses associated with the compliance projects on an interim basis until such costs are recovered in Rider 62. This treatment has been approved by the Commission in similar causes in the past and enables the Company to match revenue with the associated expenses that the revenues are intended to recover.

Q. WHAT IS THE COMPANY'S PROPOSED AMORTIZATION PERIOD FOR THE COSTS DEFERRED IN THE REGULATORY ASSET FOR THE COAL ASH CLOSURE PROJECT COSTS?

A. The Company proposes that all coal ash closure project costs be amortized such that they will be fully recovered in 2038. The year 2038 was selected to ensure costs were fully amortized by the time the Company's last operating coal unit at Gibson Station was retired in 2038, based on the retirement dates included in the depreciation study in the pending base rate case. This methodology is consistent with Cause No. 45253 in which the Company is proposing to amortize the Past coal ash costs included in rate base with an amortization period of 18 years. Because additional costs will be reflected in the rider as incurred as of each cut-off date, instead of using 18 years to compute amortization amounts in each filing, the Company proposes to use the appropriate period for each filing to ensure all costs are recovered by July 2038. For example, if the first rider filing is ECR 35 which would use a December 2020 cutoff with the expectation that it would be billed to customers beginning in July 2021, the Company would use an amortization period of 17 years (2038 less 2021) to ensure the costs are fully collected by July 2038. This ensures no matter the timing of the incurrence of the costs, they will be recovered from the customers who are benefitting while coal units are still operating, rather than leaving costs to be recovered from future customers once the coal generating facilities are retired. This is also how the Company has previously handled recovery of other deferred costs via amortization when additional costs are deferred over time in both ECR rider filings and the Company's Cause No. 43114 IGCC rider filings to ensure the costs are fully amortized by a date certain.

Q. WHY IS THE COMPANY REQUESTING APPROVAL TO USE RIDER 62 AS THE PERIODIC RETAIL RATE ADJUSTMENT MECHANISM FOR ITS FEDERALLY MANDATED COSTS?

A. As explained previously, Rider 62 (along with Rider 71 which will be combined with it, as proposed in the base rate case) currently recovers the costs of previously-approved projects for compliance with previously-enacted or promulgated environmental rules, including the federally mandated compliance projects approved by the Commission in Cause No. 44765, including projects required under the CCR Rule. The Company has proposed to maintain Rider 62 after the base rate case to include these additional CCR and IDEM federally mandated costs, as well as any other future projects that may be required for compliance with these or other environmental rules. The Company's processes for the existing Rider are established, and the OUCC, Commission staff, and other stakeholders are familiar with the methodology used.

Q. HOW ARE THE AMOUNTS IN RIDER 62 ALLOCATED TO CUSTOMERS?

A. The revenue requirement amounts are allocated to rate groups using the same coincident peak ("CP") demand allocation method adopted for production plant-related costs in the Company's most recent retail base rate case (*i.e.*, the allocators that will be approved in the currently pending base rate case for production plant will be used in the rider beginning with new base rate implementation). Rates to be billed to individual customers within a rate group are developed by dividing the revenue requirement amounts by kilowatt-hour sales, except for industrial customers served under Rate HLF, for which non-coincident peak ("NCP") KW demand is used. The Company is not proposing any changes to this allocation and rate development methodology as a result of the ratemaking proposal in the current proceeding.

Q. WILL ANY CHANGES BE NEEDED TO THE RIDER 62 TARIFF TO SUPPORT THE INCLUSION OF THE FEDERALLY MANDATED ENVIRONMENTAL COSTS PROPOSED IN THIS PROCEEDING?

A. No.

Q. WILL THE FUEL CLAUSE EARNINGS TEST BE ADJUSTED FOR APPROVED EARNINGS ON THESE FEDERALLY MANDATED PROJECTS AS REQUIRED BY INDIANA CODE § 8-1-8.4-7(c)(1)?

A. Yes. The Company already has a process in place to increase the authorized net operating income used in the Fuel Clause Earnings Test for the incremental approved earnings from Rider 62. Including the Plan investments in Rider 62 will ensure this requirement is met in an administratively efficient manner.

Q. TO WHAT EXTENT WILL COSTS BE DEFERRED AND CARRYING COSTS BE ACCRUED ON THE 20% OF THE PROJECT COSTS NOT INCLUDABLE IN RIDER 62?

A. Consistent with Indiana Code 8-1-8.4, upon Commission approval of the compliance projects included in the Plan as federally mandated costs, the Company proposes to begin the deferral of 20% of the retail jurisdictional portion of federally mandated costs in a regulatory asset and will accrue financing costs, including on any previously accrued financing cost amounts, until such costs are recovered in the Company's retail base rates. These carrying costs represent financing costs on the portion of federally mandated costs which cannot be included for timely recovery in a rider mechanism.[3]

III. RATE IMPACTS OF PROPOSED COMPLIANCE PLAN COST RECOVERY

Q. PLEASE SUMMARIZE THE PROJECTED RATE IMPACTS OF THE FEDERALLY MANDATED PROJECTS INCLUDED IN THE COMPLIANCE PLAN PRESENTED IN THIS PROCEEDING.

A. The rate impact will vary based on a number of variables, including but not limited to, the following:

- The final costs of the compliance Projects in the Plan and related costs;
- The Company's actual financing costs during the period of the project expenditures;
- The actual capital structure, cost of capital rates, and revenue conversion factors in effect for the rider filings;
- Timing of the expenditures and approvals for recovery in Rider 62;
- Actual post-closure maintenance and other ongoing costs incurred;
- Actual allocation of costs to joint owners of Gibson Unit 5;
- Timing of the next retail base rate case.

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[3] While the Company does not currently anticipate exceeding its cost estimates by more than 25%, it has proposed similar deferral treatment for any such costs.

The Company has based its rate impact calculation on the projected Plan costs and timing presented in the testimony of Mr. Thiemann using the forecasted December 31, 2020 capital structure and cost rates as presented in the Rebuttal Testimony of Ms. Douglas in Cause No. 45253 and the retail revenues under present rates forecasted for the 12 months ended December 2020 as presented in the Rebuttal Testimony of Ms. Maria T. Diaz in Cause No. 45253. The rate impact calculation amortized the closure costs as described previously to fully recover the costs over the remaining life of the last coal unit at Gibson Station (2038) and the accrued financing costs over a three-year period. Coal ash management expenditures were treated as operating expenses.

The total retail rate impact calculation on Petitioner's Exhibit 3-A (BPD) shows a first full year rate increase of 0.75% in 2022 over the forecasted 2020 revenues, with a peak year total revenue increase of 1.27% (again, over the forecasted 2020 revenues) in 2026. Petitioner's Exhibit 3-A (BPD) also shows the calculation of the estimated retail rate impact by year and customer class.

The projected rate impact does not include the cost of future projects for which the Company is not currently requesting a CPCN. The testimony of Mr. Thiemann includes a description of these projects.

IV. PROPOSED ACCOUNTING FOR OTHER CCR AND IDEM COAL ASH MANAGEMENT COSTS FOR WHICH CLOSURE PLAN APPROVAL HAS NOT YET BEEN RECEIVED FROM IDEM

Q. WHAT SPECIFIC APPROVAL ARE YOU ASKING FROM THE COMMISSION RELATED TO ACCOUNTING FOR COSTS TO BE INCURRED FOR FUTURE COAL ASH MANAGEMENT AND CLOSURE PROJECTS NOT INCLUDED IN

THE COMPLIANCE PLAN FOR WHICH APPROVAL IS REQUESTED IN THIS FILING?

A. As explained in the testimony of Mr. Schwartz, the EPA's CCR and RCRA Rules meet the definition under Indiana Code 8-1-8.4 of a federally mandated requirement. As explained in the testimony of Mr. Thiemann, there are additional future coal ash management costs for post-closure for 2029 and after and closure compliance projects required to be undertaken for direct or indirect compliance with the federally mandated requirements, but for which the Company has not yet received IDEM closure plan approval. The Company is therefore requesting authority from the Commission to continue to defer the retail jurisdictional portion of the federally mandated costs associated with these closure projects not included in the currently requested compliance Plan, support and estimates for which are presented in the testimony of Mr. Thiemann, with financing costs, for future rate recovery pursuant to Indiana Code § 8-1-8.4-7. Specifically, the Company is requesting:

- Authority from the Commission to accrue in a regulatory asset (using the Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations ("CFR") account 182.3) the federally mandated future Costs associated with these coal ash management and closure projects not included in the current compliance Plan, until they can be presented to the Commission in a proceeding requesting a CPCN under the Federal Mandate Statute and specific cost recovery under the statute and until the costs are included in retail rates.

- Authority from the Commission to accrue in a regulatory asset (using the Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations ("CFR") account 182.3) the financing costs on the federally mandated future Costs associated with these coal ash management and closure projects not included in the current compliance Plan, at rates equal to Duke Energy Indiana's most recently approved weighted average cost of capital ("WACC") – using the equity return approved by the Commission in the Company's most recent retail base electric rate case, until the costs are included in retail rates.

Q. WHAT TIMING DOES THE COMPANY ANTICIPATE FOR THE FILING OF A REQUEST FOR CPCN AND COST RECOVERY FOR THESE ADDITIONAL FUTURE COAL ASH MANAGEMENT COSTS?

A. As explained in the testimony of Mr. Schwartz, the Company expects to receive final approval of the remaining closure plans by IDEM either later this year or early in 2021. Once we receive final approval of all remaining closure plans, we will initiate a docketed filing to request a CPCN and cost recovery under the Federal Mandate Statute as soon as practicable.

V. <u>CONCLUSION</u>

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY FOR THE ACCRUAL OF FINANCING COSTS AND INTERIM DEFERRAL OF COSTS RELATED TO THE 80% RECOVERY OF COMPLIANCE PLAN COSTS IN RIDER 62, FOR DEFERRAL WITH FINANCING COSTS OF THE

REMAINING 20% OF PLAN COSTS, FOR DEFERRAL WITH FINANCING COSTS OF ANY EXCESS OVER 25% OF PROJECTED PLAN COSTS, AND DEFERRAL WITH FINANCING COSTS OF ADDITIONAL FUTURE COAL ASH MANAGEMENT AND CLOSURE FEDERALLY MANDATED COSTS NOT INCLUDED IN THIS COMPLIANCE PLAN IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag. Topic 980 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for accounting purposes, provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

Q. DO YOU HAVE AN OPINION AS TO THE APPROPRIATENESS OF, AND THE ACTION REQUIRED BY, THE COMMISSION TO ALLOW FOR THE REQUESTED ACCOUNTING TREATMENT?

A. Yes. In my opinion, deferral in a regulatory asset of the retail jurisdictional portion of the federally mandated costs of the Plan to comply with CCR and RCRA and of additional federally mandated coal ash management and closure costs that are mandated under the same environmental rules and are therefore eligible for recovery under the Federal Mandate Statute, but for which closure plans are not yet approved by IDEM, until they can be included in rider rates or base rates, is appropriate from a ratemaking perspective, and such treatment will minimize the timing differences between cost recognition on the Company's books and cost recovery. In addition, Indiana Code 8-1-8.4 specifically provides for the timely recovery of financing costs associated with federally mandated compliance projects.

In order for the Company to defer the federally mandated costs as a regulatory asset, it must be probable that such costs will be recovered through rates in future periods. In order to satisfy the probability standard, the Commission's Order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Energy Indiana.

Q. WAS PETITIONER'S EXHIBIT 3-A (BPD) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes.

Duke Energy Indiana, LLC

Estimated Retail Revenue Requirement and Rate Impacts for
Coal Ash Compliance Plan Costs to be Included in Rider 62
(dollars in thousands)

Line No.	Description	Support Reference	2021	2022	2023	2024	2025	2026	2027	2028	Total	Line No.
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
	Investment											
1	Return on Closure Costs and Accrued Financing Costs	WP-1	$ 1,610	$ 6,443	$ 9,596	$ 11,566	$ 12,769	$ 13,298	$ 12,994	$ 11,991	$ 80,267	1
	Operating Costs											
2	Amortization of Closure Costs	WP-2	2,867	7,832	10,179	12,188	13,778	14,676	14,872	14,878	91,270	2
3	Coal Ash Management Costs	WP-3	12,926	2,456	1,352	2,064	1,943	2,148	2,194	2,243	27,326	3
4	Amortization of Accrued Financing Costs (on Closure and Coal Ash Management Costs)	WP-4	443	2,000	3,045	3,398	2,450	1,881	1,381	151	14,749	4
5	Total Operating Costs Revenue		16,236	12,288	14,576	17,650	18,171	18,705	18,447	17,272	133,345	5
6	Utility Receipts Tax @ 1.4%	(Line 1+Line 5)*.014	250	262	338	409	433	448	440	410	2,991	6
7	**Total Revenue Requirement**		**$ 18,096**	**$ 18,993**	**$ 24,510**	**$ 29,625**	**$ 31,373**	**$ 32,451**	**$ 31,881**	**$ 29,673**	**$ 216,603**	7
8	**Annual Revenue Requirement Increase (Decrease)**		**$ 18,096**	**$ 897**	**$ 5,517**	**$ 5,115**	**$ 1,748**	**$ 1,078**	**$ (570)**	**$ (2,208)**	**$ 29,673**	8
9	**2020 Forecasted Revenue**	Cause No. 45253	$ 2,547,576	$ 2,547,576	$ 2,547,576	$ 2,547,576	$ 2,547,576	$ 2,547,576	$ 2,547,576	$ 2,547,576		9
10	**Percent Increase for Total Revenue Requirement**	Line 7 / Line 9	**0.71%**	**0.75%**	**0.96%**	**1.16%**	**1.23%**	**1.27%**	**1.25%**	**1.16%**		10
11	**Annual Percent Increase (Decrease)**		**0.71%**	**0.03%**	**0.21%**	**0.20%**	**0.07%**	**0.04%**	**(0.02%)**	**(0.09%)**		11

Note:
ECR 33 is currently and assumed to be in effect until 6/30/2020 (with new base rates assumed to be going into effect 7/1/2020); reconciliation of July 2018 thru December 2018, forecast January 2019 thru June 2019.
With the implementation of new base rates - Rider rates will be updated to exclude what is included in base rates.
ECR 34 is anticipated to be filed in September 2020 -- this will be the reconciliation of January 2019 thru June 2020; projected January 2021 thru June 2021 - rates assumed to go into effect 1/1/2021.
With the hearing being schedule for September 2020, will not include any costs related to the subdocket.
ECR 35 will be reconciliation of July 2020 thru December 2020 for non sub-docket, January 2019 thru December 2020 for sub-docket, projected July 2021 thru December 2021.

Duke Energy Indiana, LLC

Estimated Retail Revenue Requirement and Rate Impacts for
Coal Ash Compliance Plan Costs to be Included in Rider 62
(dollars in thousands)

Line No.	Description		2021	2022	2023	2024	2025	2026	2027	2028	Total	Line No.
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
1	Total Revenue Requirement (page 1 line 10)		$ 18,096	$ 18,993	$ 24,510	$ 29,625	$ 31,373	$ 32,451	$ 31,881	$ 29,673		1
	Rate Code	Allocation (1)										
2	RS	42.13%	$ 7,624	$ 8,002	$ 10,326	$ 12,481	$ 13,218	$ 13,672	$ 13,432	$ 12,501		2
3	CS	5.17%	936	982	1,267	1,532	1,622	1,678	1,648	1,534		3
4	LLF	20.72%	3,749	3,935	5,079	6,138	6,501	6,724	6,606	6,148		4
5	HLF	30.77%	5,568	5,844	7,542	9,116	9,654	9,985	9,810	9,130		5
6	All Other	1.21%	219	230	296	358	378	392	385	360		6
7	Total	100.00%	$ 18,096	$ 18,993	$ 24,510	$ 29,625	$ 31,373	$ 32,451	$ 31,881	$ 29,673		7
	Percent Increase for Total Revenue Requirement											
	Rate Code	2020 Forecasted										
8	RS	$ 1,007,029	0.76%	0.79%	1.03%	1.24%	1.31%	1.36%	1.33%	1.24%		8
9	CS	123,490	0.76%	0.80%	1.03%	1.24%	1.31%	1.36%	1.33%	1.24%		9
10	LLF	481,511	0.78%	0.82%	1.05%	1.27%	1.35%	1.40%	1.37%	1.28%		10
11	HLF	857,786	0.65%	0.68%	0.88%	1.06%	1.13%	1.16%	1.14%	1.06%		11
12	All Other	77,760	0.28%	0.30%	0.38%	0.46%	0.49%	0.50%	0.50%	0.46%		12
13	Total	$ 2,547,576	0.71%	0.75%	0.96%	1.16%	1.23%	1.27%	1.25%	1.16%		13
	Annual Percent Increase (Decrease)											
14	RS		0.76%	0.04%	0.23%	0.21%	0.07%	0.04%	(0.02%)	(0.09%)		14
15	CS		0.76%	0.04%	0.23%	0.21%	0.07%	0.04%	(0.02%)	(0.09%)		15
16	LLF		0.78%	0.04%	0.24%	0.22%	0.07%	0.05%	(0.02%)	(0.09%)		16
17	HLF		0.65%	0.03%	0.20%	0.18%	0.06%	0.04%	(0.02%)	(0.08%)		17
18	All Other		0.28%	0.01%	0.08%	0.08%	0.03%	0.02%	(0.01%)	(0.03%)		18
19	Total		0.71%	0.03%	0.21%	0.20%	0.07%	0.04%	(0.02%)	(0.09%)		19

(1) per Pending Rate Case Cause No. 45253 - 4CP - Workpaper 5 (BPD)

Note:
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VERIFICATION

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

Signed: Brian P Davey
Brian P. Davey

Dated: 4/15/2020