ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC) CAUSE NO. 45253 S 1
FOR APPROVAL OF A FEDERAL MANDATE)
CERTIFICATE UNDER IND. CODE § 8-1-8.4-1) APPROVED: NOV 03 2021

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Sarah E. Freeman, Commissioner
David E. Veleta, Senior Administrative Law Judge

On July 2, 2019, Duke Energy Indiana, LLC ("Duke Energy Indiana", "Petitioner" or "Company") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Petition for General Rate Increase and Associated Relief in Cause No. 45253. As part of its case-in-chief in Cause No. 45253, Duke Energy Indiana requested a certificate of public convenience and necessity under Indiana Code § 8-1-8.4-7(b) for estimated future federally mandated ash pond closure costs. On December 5, 2019, the Commission removed this issue from the main proceeding, pursuant to 170 Ind. Admin. Code 1-1.1-21, and initiated this subdocket proceeding for the consideration of Petitioner's future Coal Combustion Residuals ("CCR") closure costs.

Counsel for Duke Energy Indiana, the Office of Utility Consumer Counselor ("OUCC"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Duke Industrial Group ("IG"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), and the Department of Navy on behalf of the Federal Executive Agencies ("Navy") entered Appearances in this subdocket proceeding.

On April 15, 2020, Petitioner prefiled its case-in-chief, which included the direct testimony and exhibits of the following witnesses: Owen R. Schwartz, Manager Waste and Groundwater Programs Group at Duke Energy Business Services LLC ("DEBS"); Timothy J. Thiemann, General Manager of CCP Project Management Midwest at DEBS; and Brian P. Davey, Vice President Rates and Regulatory Strategy at Duke Energy Indiana.

On July 22, 2020, the OUCC prefiled the direct testimony of the following: Cynthia M. Armstrong, Senior Utility Analyst in the Electric Division; Wes R. Blakley, Senior Utility Analyst in the Electric Division; and Anthony A. Alvarez, Utility Analyst in the Electric Division. On July 24, 2020, Petitioner filed its second motion for protection of confidential and proprietary information, which was preliminary granted on July 28, 2020.

On August 17, 2020, Duke Energy Indiana prefiled the rebuttal testimony of Owen Schwartz, Tim Thiemann, David Raiford, and Brian Davey.

An evidentiary hearing was held in this Cause on September 14, 2020, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. The parties appeared by counsel, and the prefiled evidence of Duke Energy Indiana and the OUCC was admitted into the record without objection.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. Notice and Commission Jurisdiction. Notice of the hearing in this Cause was given and published as required by law. Duke Energy Indiana is a public utility as that term is defined in Indiana Code §8-1-2-1(a) and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. Petitioner's Characteristics. Duke Energy Indiana is a public utility and an Indiana corporation with its principal office located in Plainfield, Indiana. Petitioner is engaged in the business of rendering retail electric utility service and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service. Duke Energy Indiana provides electric service to approximately 840,000 customers in 69 Indiana counties. Petitioner also sells electric energy for resale to other electric utilities and cooperatives.

3. Relief Requested. Petitioner requests the following: 1) a certificate of public convenience and necessity under Indiana Code § 8-1-8.4-7(b) for estimated future federally mandated ash pond closure costs for Petitioner's closure plans approved by Indiana Department of Environmental Management ("IDEM") as of April 1, 2020, along with ongoing post-closure maintenance and non-basin closure costs through 2028; and 2) deferral of the retail jurisdictional portion of the federally mandated closure costs for closure plans not included in this current plan, including financing costs on an interim basis.

4. Petitioner's Case-in-Chief. Mr. Schwartz described the U.S. Environmental Protection Agency's ("EPA") CCR standards and requirements. He testified that under the CCR Rule, there are certain events that may cause a CCR unit to trigger closure. Certain of Petitioner's surface impoundments triggered closure as a result of location restrictions and structural integrity and safety factor assessments – specifically, Gallagher Primary Pond, Gibson North Ash Pond, and Cayuga Primary Ash Settling Pond and Line Ash Disposal Area. Gallagher Ash Pond A had to undertake remediation activities to bring it into compliance with the structural integrity and safety factor requirement by October 17, 2016. Petitioner's Wabash River Ash Pond A and Ash Pond B, and Wabash River Secondary Setting Pond triggered closure by exceeding applicable groundwater standards. Finally, Petitioner's Cayuga Secondary Ash Settling Pond, Gallagher Secondary Settling Pond, Gibson North Settling Basin, Gibson East Ash Pond Settling Basin, and Gibson South Settling Basin were required to initiate closure based on their receiving their last known quantities of CCR and station water. Mr. Schwartz testified that, absent extenuating circumstances, the CCR Rule requires closure be complete within five years of its initiation. However, up to five two-year extensions are available for surface impoundments greater than forty acres in area, for a maximum potential closure duration of fifteen years. Mr. Schwartz testified that following closure in place of surface impoundments and landfills, the owner/operator is responsible for maintaining the integrity and effectiveness of the final cover system, the leachate collection and removal system (if present), and the groundwater monitoring system. He testified the default post-closure care period is thirty years, or until post-closure standards have been achieved. Mr. Schwartz testified Closure and Post Closure Plans have been submitted to IDEM for all of Duke Energy Indiana's surface impoundments with many having been approved. He estimates the remaining Plans will be approved by or before early 2021.

Mr. Schwartz testified that the Resource Conservation and Recovery Act ("RCRA") establishes a nationwide system of solid waste management and control, with solid waste including solids, liquids and gases and must be discarded to be considered waste. Mr. Schwartz explained the connection between closing coal ash management areas and Federal law. He testified that Petitioner's actions to address final closure of historic ash management areas at the former Dresser and Noblesville Stations, and the repurposed Edwardsport Station, are being conducted in compliance with state law and accompanying regulations, which are in turn required by Federal law and explicitly reviewed and approved by the EPA. Similarly, Gibson Station's East Ash Pond closure plan was to comply with state regulations that are required by Federal law and reviewed by the EPA. Mr. Schwartz also explained the development of Indiana's EPA-approved regulations related to solid waste management and coal ash. He testified that Duke Energy Indiana closed ash management areas at Noblesville Station, a non-CCR Rule ash management area, to comply with State requirements. Mr. Schwartz testified that allowing rate recovery for the closure of non-CCR Rule ash areas provide a powerful additional incentive for utilities to proactively initiate actions to identify, investigate, close, and, if necessary, remediate numerous historic ash management areas across the state.

Mr. Schwartz testified that compliance with the CCR, RCRA and IDEM rules is mandatory. Even though the State of Indiana is implementing the RCRA requirements through its solid waste management rules, those requirements from IDEM are also mandatory. He testified that as the CCR Rule was promulgated under RCRA, it meets the definition of a "federally mandated requirement." Similarly, the CCR compliance projects proposed by Petitioner meet the definition of a "compliance project" as they are being undertaken and relate to the direct or indirect compliance with one or more federally mandated requirements – the CCR Rule. Additionally, IDEM's solid waste management plan allows the State to demonstrate how CCR units will be regulated in Indiana, including how Indiana intends its state requirements to relate to the federal regulations, making Petitioner's projects related to the direct or indirect compliance with a "federally mandated requirement." Therefore, the proposed compliance projects mandated by IDEM also meet the definition of "compliance projects."

Mr. Thiemann described the projects Petitioner must undertake to either close in place or close by removal its surface impoundments, along with post-closure care and maintenance through 2028, which comprise Petitioner's coal ash compliance plan for which it requests CPCN approval in this proceeding. He also described future compliance projects, although not requested for approval in this proceeding. Mr. Thiemann testified Petitioner anticipates a separate regulatory filing for these future projects once IDEM approval is obtained, which is expected to occur by approximately 2021.

Mr. Thiemann testified that costs associated with the Lined Ash Disposal Area, Ash Disposal Area #1, and the Primary Ash Settling Pond for Cayuga Station are included in this proceeding. IDEM approved closure of the Cayuga ash pond system on January 17, 2020, setting forth the following methods of closure: Lined Ash Disposal Area, approximately 36.9 acres, will be closed in place with a CCR Rule-compliant capping system integrated with the Ash Disposal Area #1 area. Ash Disposal Area #1, approximately 101 acres, is an inactive area at which Petitioner is executing a closure in place with a CCR Rule-compliant capping system integrated with the Lined Ash Disposal Area. Primary Ash Settling Pond, approximately 26 acres, will be closed in place with all CCR materials removed, which entails removing all visible CCR materials followed by the placement of fill materials in such a manner to prevent ponding of water on the surface.

Mr. Thiemann testified that Petitioner plans to have the ash management areas at Cayuga closed by 2023 and provided a milestone schedule as Confidential Exhibit 2-B.

Mr. Thiemann testified IDEM partially approved the Gallagher ash pond system closure, for all areas but the Primary Pond, on December 10, 2019. In February 2020 Petitioner submitted modifications to IDEM for the Primary Pond, which are still under consideration. Mr. Thiemann testified that costs associated with the North Ash Pond, Primary Pond Ash Fill Area, Ash Pond A, and Ash Pond B/Landfill are included in this proceeding. He testified that costs for the Gallagher Secondary Settling Pond are not included in this proceeding since they were included in Duke Energy Indiana's retail base rate case (Cause No. 45253). Gallagher Ash Fill Area #1 will be repurposed for use as a new lined retention pond. These associated costs are also not included in this proceeding. Mr. Thiemann testified that the following portions of the Gallagher ash pond system are included in this proceeding: North Ash Pond, approximately 39.9 acres, will be closed in place with implementation being scheduled for the 2022 timeframe. A CCR Rule-compliant cap will be integrated with the Primary Pond and the Primary Pond Ash Fill Area. Ash Pond A, approximately 36 acres, will be closed by removal of all CCR materials with the material being placed in the on-site restricted waste landfill. Ash Pond B/Landfill was repurposed years ago into the on-site restricted waste landfill, which is being closed for CCR Rule compliance. IDEM approved an extension of the cover system for the landfill to include those areas of Ash Pond B outside the boundary of the restricted waste landfill. Primary Pond Ash Fill Area, approximately 7.5 acres, will be closed in place with an integrated cap with the Primary Pond and North Ash Pond utilizing a CCR Rule-compliant cap.

Mr. Thiemann testified that Petitioner plans to have the ash management areas at Gallagher closed by 2025 and provided a milestone schedule as Confidential Exhibit 2-D.

Mr. Thiemann testified IDEM partially approved the South Ash Pond system for Wabash River Station, covering Ash Pond A, the Secondary Settling Pond, and the South Ash Pond, on August 16, 2019. IDEM is continuing to evaluate Petitioner's revised proposed closure by removal of Ash Pond B, as well as the North Ash Pond, which are not included for approval in this proceeding. Mr. Thiemann testified that the following portions of the Wabash River ash pond system are included in this proceeding: Ash Pond A, approximately 80.2 acres, will be closed by removal with the material being placed in the lined South Ash Pond. Secondary Settling Pond, approximately 7.8 acres, will be closed by removal with the material being placed in the lined

South Ash Pond. A soil structural fill buttress will also be constructed in this footprint to provide stabilization and protection of the South Ash Pond from river flooding. South Ash Pond, approximately 73 acres, will be closed in place by consolidating materials from Ash Pond A, Ash Pond B and the Secondary Settling Pond to establish final grades.

Mr. Thiemann testified that Petitioner plans to have the ash management areas at Wabash River closed by 2027 and provided a milestone schedule as Confidential Exhibit 2-F.

Mr. Thiemann testified that in addition to the CCR Rule-mandated requirements, Petitioner has been undertaking coal ash-related remediation under Indiana's Solid Waste Regulations at the Gibson East Ash Pond (under a state approved closure plan prior the CCR Rule), the former Dresser Generating Facility in West Terre Haute, and the Noblesville Generating Facility (both under Agreed Orders and closure plans approved by the State of Indiana). Mr. Thiemann testified that this proceeding includes only costs from the approved closure plans at the former Dresser Generating Station and at Noblesville Generating Station, as well as certain coal ash management costs after 2020 associated with the Gibson East Ash Settling Basin. Expenses through 2020 associated with the Gibson East Ash Pond and Dresser were included in Cause No. 45253. Mr. Thiemann testified the closure plan for legacy Edwardsport remains pending before IDEM and is not included in this proceeding.

Mr. Thiemann testified that only relatively minor expenses remain for the Gibson East Ash Pond system, made up of the East Ash Pond and the East Ash Settling Basin, and have been included in this proceeding. He testified the East Settling Basin closure plan was amended such that it would be closed under the CCR Rule. The East Ash Pond closure was previously approved by the state and is not subject to the CCR Rule. He testified that IDEM has not yet approved the closure plans for the North Ash Pond, North Settling Basin, South Ash Fill Area, and South Settling Basin, and they are therefore not included in this proceeding. Mr. Thiemann testified that Petitioner plans to have the ash management areas at Gibson mostly closed by 2023 and provided a milestone schedule as Confidential Exhibit 2-G.

Mr. Thiemann testified that the Dresser Closure Implementation Plan consists of two main areas, a mine refuse management area and a coal ash management area. IDEM approved the closure/post closure plan on December 21, 2017. He testified the Mine Refuse Management Area, approximately 18 acres, contains refuse from mining operations from the mid-1920s to the 1950s consisting of clay, underclay, shale, etc. The mine refuse materials are planned to remain in place but the face along the Wabash River will be pulled back, flattened, and armored up to the 100-year flood elevation. Mr. Thiemann testified that the Coal Ash Management Area, approximately 48 acres, consists generally of bottom ash and cinders which will be consolidated into one pile in the vicinity of the former coal pile. In addition, Petitioner has located asbestos-containing material in two piles in this area. The average thickness of ash is approximately 5 feet. The asbestos-containing material is being consolidated on site, grading and covered in accordance with the approved closure plan. Mr. Thiemann testified that both the mine refuse and coal ash management areas will receive a nominal 2 feet compacted soil cover followed by a 6-inch topsoil layer to support vegetation. Groundwater monitors will also be installed. A milestone schedule for the Dresser remediation work was provided as Confidential Exhibit 2-I.

Mr. Thiemann testified that the Noblesville closure plan, approved by IDEM on October 17, 2019, addressed the ash management areas generally consisting of two contiguous ash disposal areas in the northwest portion of the station property. The disposal areas were covered with some soils ranging from nominal to as much as 2 feet. Grass was sown and trees were planted. He testified that the overall closure plan is to excavate these CCR materials and consolidate them in one ash management area along the western boundary of the property. This consolidated pile would be covered with a 6-inch layer of cohesive soils followed by a textured geomembrane and geo-composite drainage layer. A 30-inch layer of protective soils plus a 6-inch vegetative layer will be placed over the drainage layer. A network of groundwater interceptor wells was installed and is in operation. A milestone schedule was provided as Confidential Exhibit 2-K.

Mr. Thiemann testified that Petitioner evaluated alternative closure methods and each option is included in the closure plan documents. Each ash management area was reviewed for the best and most cost-effective way to comply with the federal CCR requirements. Mr. Thiemann testified that there are not numerous alternatives to closing its surface impoundments as mandated by the CCR Rule. It can close its surface impoundments by closure by removal or by closure in place. He testified that the only real "alternative" is the alternative that IDEM approves. He also testified that the closure of a basin at a particular site does not extend the useful life of the generating facility.

Mr. Thiemann testified that Petitioner is requesting a total of approximately $302 million (unescalated and after subtracting cost of removal) in closure expenses in this proceeding, plus approximately $35 million in coal ash management costs (unescalated). He provided a detailed estimate in Confidential Exhibit 2-L and workpapers. Mr. Thiemann explained that Petitioner is only requesting expenses through 2028 in this proceeding, with future expenses of approximately $250 million to be requested in a subsequent proceeding upon approval of its closure plans by IDEM. He testified that there will also be post-retirement closure projects and Operations and Management. He identified these future closure projects, and testified that these future projects, including 30 years post closure maintenance, are estimated to cost approximately $150 million (not escalated).

Mr. Thiemann testified that he believes Petitioner has proceeded reasonably in the activities it has undertaken for CCR and IDEM Rule Compliance, and that its coal ash-related compliance costs are reasonable and should be approved.

Mr. Davey testified that Petitioner 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. Past Costs include costs 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. Future costs have been updated to reflect the current status of state closure plan approvals, as of April 1, 2020, with the latest timing and cost estimates and include certain ongoing post-closure maintenance and non-basin closure costs. He testified the coal ash management closure costs have been estimated through 2028 for this proceeding and in determining rate impact.

Mr. Davey testified that Petitioner is requesting (1) approval of the use of its existing Rider 62, with revisions as proposed in Cause No. 45253, for timely recovery of 80% of the retail jurisdictional portion of Plan costs including capital, operating, maintenance, depreciation, tax or financing costs; (2) authority to use a regulatory asset 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 to accrue financing costs on the 80% of retail jurisdictional portion of the expenditures under the Plan at rates equal to Petitioner's most recently approved weighted average cost of capital ("WACC"), using the equity return approved in Petitioner's most recent retail base electric rate case, until the costs are included in retail rates; (4) authority to accrue a regulatory asset (using Federal Energy Regulatory Commission ("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 Petitioner's most recently approved WACC – using the equity return approved in Petitioner'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 Petitioner's retail base rates after a general retail rate case; and (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.

Mr. Davey testified that, upon Commission approval of the compliance projects included in this proceeding, Petitioner 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 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. He testified that Petitioner would continue this ratemaking treatment until these projects are used and useful and included in a proceeding that involves the establishment of Petitioner's base retail electric rates and charges.

Mr. Davey testified that Petitioner 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 until such expenditures and accrued financing costs are recovered in Petitioner's retail rates. He testified that for Generally Accepted Accounting Principles ("GAAP") accounting and reporting purposes, Petitioner 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. Petitioner will 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.

Mr. Davey testified that Petitioner proposes all coal ash closure project costs be amortized for full recovery by 2038, which is when the last operating coal unit at Gibson Station will be retired. He testified that this methodology is consistent with Cause 45253 in which Petitioner proposes 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, Petitioner proposes to use the appropriate period for each filing to ensure all costs are recovered by July 2038. Mr. Davey testified that it 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.

Mr. Davey testified Petitioner proposed to maintain Rider 62 after the base rate case to include 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. Petitioner is not proposing any changes to the allocation and rate development methodology in this proceeding. 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 Petitioner's most recent retail base rate case. 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. Mr. Davey testified that no changes are needed to the Rider 62 tariff for inclusion of the federally mandated environmental costs proposed in this proceeding. He testified that the fuel clause earnings test will be adjusted for approved earnings on these federally mandated projects. Mr. Davey testified that upon Commission approval of the compliance projects included in the Plan as federally mandated costs, Petitioner will 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 Petitioner'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.

Mr. Davey testified the projected rate impact of the federally mandated projects included in this proceeding 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% in 2026.

Mr. Davey testified that Petitioner is seeking authority to accrue in a regulatory asset the federally mandated future costs associated with coal ash management and closure projects not included in this current compliance Plan, until they can be presented in a future proceeding. In addition, Petitioner is seeking authority to accrue in a regulatory asset the financing costs on federally mandated future costs associated with the coal ash management and closure projects not included in this current compliance Plan, at rates equal to Petitioner's most recently approved WACC – using the equity return approved by the Commission in Petitioner's most recent retail base electric rate case, until the costs are included in retail rates.

Mr. Davey testified that its proposed accounting treatment in this proceeding is in accordance with GAAP and is appropriate.

5. **<u>OUCC Direct Testimony</u>.** Ms. Armstrong testified that Petitioner's ash pond closures are necessary as they do not meet requirements for existing surface impoundments under the CCR Rule and, therefore, must close. She testified the ash pond closures qualify as "federally mandated costs" as defined under Indiana Code § 8-1-8.4-4, however costs related to IDEM Agreed Orders should not be recoverable from ratepayers. Ms. Armstrong testified that environmental groups are concerned with IDEM approval of any plan that allows Petitioner to close unlined impoundments in place, particularly if the impoundments have the ability to temporarily or permanently remain in contact with groundwater. Hoosier Environmental Council is appealing IDEM's partial approval of Gallagher's ash pond system closure plant. Although Petitioner is confident in IDEM's approval of Gallagher, it admits that any adverse final decision could increase the costs of basin closures. Ms. Armstrong testified that if the Commission's findings regarding CCR closure costs in its final order in Cause No. 45253 stand, the OUCC cannot recommend approving any portion of Petitioner's CCR closure plans involving closure in place at Cayuga, Gallagher, and Wabash River. While the standards for closure in place ("CIP") are designed to minimize risk of precipitation infiltrating ash left in place, she testified that there is a risk that ash could come into contact with groundwater over time and could leak dangerous metal constituents into surrounding groundwater in the future. Ms. Armstrong testified that it does not appear that Petitioner included statistical-based measure of risk and potential of additional costs of corrective actions in its support for its CCR Compliance Plan that a CIP option could have in comparison to a closure by removal ("CBR") option. If allowed to recover costs associated with the IDEM Agreed Orders, ratepayers far into the future (30 or more years) would be exposed to the risk of paying these costs without receiving the benefit of the generating plants the costs are tied to.

Ms. Armstrong testified that the OUCC disagrees with the costs related to IDEM Agreed Orders being characterized as federally mandated costs as Petitioner must show its decision to enter into the agreement was prudent, just and reasonable for inclusion in customer rates. She testified that while Petitioner's decision may be prudent and advantageous to Duke Energy Indiana, it may not necessarily be prudent for its ratepayers. Ms. Armstrong testified that although Petitioner does not admit to the violations listed in the IDEM Agreed Orders, it is doubtful it could have avoided liability for the alleged violations had it litigated them fully or waited until either IDEM, public health authorities, or citizens discovered them. Ms. Armstrong testified in response to Mr. Schwartz' statement that allowing rate recovery for costs relating to activities arising from an Agreed Order provides a "powerful additional incentive for utilities to proactively (rather than reactively) initiate actions to identify, investigate, close, and if necessary, remediate numerous historic ash management areas across the state." She stated that the proposition that Petitioner needs an additional incentive to ensure its old waste management unit are not contaminating groundwater and surrounding properties is self-serving and concerning. She testified that while closure of the legacy CCR waste management sites were not explicitly regulated at the time Petitioner closed them, there were laws and regulations that provided an incentive to mitigate any migration of waste constituents to surrounding properties, such as Indiana's "open dump" regulations and the Comprehensive Environmental Response Compensation and Liability Act. Although Mr. Schwartz correctly pointed out the Commission historically has allowed equipment associated with consent decrees to be recoverable, the Commission has also denied costs when a utility litigated environmental claims the EPA made against it and lost. Ms. Armstrong testified that this creates an incentive for utilities to rarely litigate violations as it is more likely to receive recovery of consent decree costs and may be able to negotiate lower civil penalties. It also creates an incentive for the utility to propose more costly compliance projects. Ms. Armstrong testified that by entering a consent decree, the utility can shift all risk of potential non-compliance with environmental laws onto ratepayers which creates a power imbalance as the OUCC is precluded from participating in settlement negotiations for consent decrees or agreed orders. She testified that with the exception of Gibson East Ash Pond, the coal units targeted by the IDEM Agreed Orders are no longer in service, thus ratepayers have already adequately compensated Petition for these costs in past rates. Ms. Armstrong does not disagree with IDEM's assessment that the Agreed Orders are in the public interest, but recommends the Commission deny the recovery of costs of the IDEM Agreed Orders from ratepayers.

Ms. Armstrong testified that while Petitioner selected to close the sites in a manner consistent with standard industry practice, it assumed this risk when it retired its generating facilities and disposed of its CCR materials in a manner that led to these legacy sites contaminating surrounding land. She referenced the Commission's prior order in Cause No. 39353, where the Commission denied Indiana Gas's recovery of clean-up costs related to Manufactured gas Plant ("MGP") sites. She testified that the Indiana Gas case is relevant to the ash pond closure costs in this Cause as it involves recovering remediation costs of an asset no longer providing service to customers. Ms. Armstrong testified that the plants are not in service and do not provide energy to Petitioner's customers. She testified that Mr. Schwartz' stating in Cause No. 45253 that the retired Edwardsport, Dresser and Noblesville stations support ongoing utility operations does not change the fact the units were retired years ago.

Ms. Armstrong testified that regardless of the Commission findings in Cause No. 45253 that CCR closure costs are acceptable and that ratepayers should bear all risk of any future remediation actions, the OUCC maintains that costs associated with IDEM Agreed Orders, and specifically Dresser Station, should not be recoverable from ratepayers as they are no longer used and useful and have not provided actual service to ratepayers in many years. Ms. Armstrong testified if ratepayers are fully responsible for any corrective action and remediation costs Petitioner incurs in the future related to generating facilities and coal ash impoundments no longer in service, she cannot recommend approving its closure plans as currently proposed. She testified that future corrective actions on a closure in place option could cost ratepayers more than if Petitioner closed all of its remaining impoundments by removal, and therefore the Commission should not approve this option. She also testified that since Petitioner is reusing the ash from ponds closed by removal as structural fill to close the other ponds in place, Petitioner's estimated costs for closing these ponds cannot be approved either, as they will be inaccurate. Although closure by removal will cost more than closure in place, it would mitigate the risk of future ratepayers being subjected to substantial remediation costs related to the closed CCR units. Ms. Armstrong testified that if the Commission denies Petitioner's recovery of legacy waste costs associated with IDEM Agreed Orders, she recommends approving the closure costs associated with CCR Rule compliance at Cayuga, Gallagher, and Wabash River Generating Stations. She also recommended Petitioner mitigate remediation costs by seeking reimbursement from insurance policies to offset overall project costs, and for Petitioner to provide regular status updates regarding its progress toward claim reimbursement in each Environmental Cost Recovery ("ECR") proceeding.

Mr. Blakley testified that Asset Retirement Obligations ("AROs") are estimated costs and not assets requiring an expenditure. They are a legal obligation recognized on the balance sheet representing future costs associated with the retirement, removal, and clean-up of a long-lived asset. He testified that AROs are not included as plant investment to earn a return "on" in a base rate case and should not be converted to a regulatory asset for inclusion in a federally mandated tracker as Petitioner proposes. Only actually incurred plant investment should be included for a return "on" in a base rate case or in a federally mandated tracker. He testified that an ARO is an estimated future cost of removal charged to accumulated depreciation at the time actual removal costs are incurred.

Mr. Blakley disagreed with Petitioner's claim that the regulatory asset treatment of coal ash pond removal costs produces similar recovery to what it would receive under traditional retirement accounting. He testified that incurred removal costs are not investments, but instead are costs charged to the accumulated depreciation account as a result of the retirement and removal of the coal ash ponds. As removal costs are incurred during retirement, the accumulated depreciation account is debited or charged for the actual costs which ultimately impacts depreciation rates in a depreciation study, which is both standard and traditional. He testified that isolating one asset's cost of removal from the retirement process and treating it as a regulatory asset to receive direct earnings "on" and "of" (including operating expenses), as the Federal Mandate Statute provides, is a non-traditional form of recovering these costs. He testified that pulling out one particular asset's removal cost and treating it as a tracked regulatory asset is unfair to Petitioner's customers because they do not receive the benefit of both charges and credits of all the other retired assets' impacts on the accumulated depreciation. It is "cherry-picking" costs of removal as a result of a retirement, which is unreasonable, unfair to customers and contrary to traditional regulatory policy.

Mr. Blakley discussed the traditional accounting process for utility plant retirement and testified that Petitioner uses composite depreciation rates for a majority of its property, plant, and equipment. He testified that with composite or group depreciation, when the cost of removal is charged ("debited") to the accumulated depreciation account as a result of retirement accounting, the reduction in the accumulated depreciation account will increase the depreciation rate. This increase permits the recovery of the cost of removal through depreciation rates based on an updated depreciation study. Mr. Blakley testified that Ms. Douglas' description in Cause No. 45253 of how early retirements may cause the retirement of the plant or cost of removal not to be charged to accumulated depreciation, would be extraordinary and occur only if the Commission orders that upon retirement the remaining net book value be recorded as a regulatory asset. Mr. Blakley testified that typical cost of removal gets charged to accumulated depreciation and no other Indiana utility, to his knowledge, has asked for an extraordinary retirement request that would also include the creation of a regulatory asset for the cost of removal. Mr. Blakley testified that it appears Petitioner chose not to treat the coal ash removal costs as an actual removal due to the existence of the Federal Mandate Statute with its current recovery of investment through return on and return "of," including operating expenses.

Mr. Blakley testified that the OUCC does not support Petitioner's request to defer Federal Mandate project costs that exceed the Commission-approved estimated costs by more than 25%. He testified that Petitioner is asking the Commission to ignore the plain language of the statute, requesting deferred accounting treatment for costs that exceed the estimate by more than 25% in the same manner as the 20% of approved total costs that are deferred. In summary, Mr. Blakley recommended the Commission (1) require traditional ratemaking in accounting for Petitioner's coal ash pond closure and removal costs by charging to its accumulated depreciation account; (2) limit Petitioner's recovery to actual CCR pond closure and removal costs that are incurred during the retirement of the facilities; (3) limit Petitioner's request for deferred accounting treatment and recovery to a return "of," with an 18-year amortization period and no carrying charges applied for actually incurred CCR pond closure and removal costs; and (4) deny Petitioner's request for deferred accounting treatment for costs exceeding the estimated costs by more than 25% in the same manner as the 20% of approved total costs that are deferred.

Mr. Alvarez described Petitioner's proposed closure plans and project management. He testified that Petitioner's case-in-chief lacks critical information needed to establish the project baseline costs, or to support the project costs in Petitioner's Confidential Exhibit 2-L (TJT). He testified that through discovery Petitioner provided recent CCP Executive Summary Report and Monthly Executive Project Status Reports as examples of its project management reports. These project management reports contain cost information along with other useful information, establishing the project baseline schedules. Mr. Alvarez testified that without a detailed cost breakdown to establish the baseline cost of a project, there is no specifically defined starting point to track and assess future cost movements and project performance. He testified that Petitioner should provide a detailed cost breakdown of the cost types (*i.e.*, direct, indirect, and overhead costs), and define the cost components within each type of cost. He testified that Mr. Thiemann's direct testimony offers no information regarding estimated contingency amounts within each project's costs. However, the CCP Executive Summary Reports provided in discovery clearly showed there were contingency funds in each project, as well as amounts drawn and amounts remaining. He testified that although each project's total contingency funds may depend on risk, in terms of total project cost ("TPC"), the percentages varied widely from 1.6% to 20%, with most at 10% to 12%. Because Petitioner already included some project closure costs in its recent base rate case, there is no way of knowing how much of the contingency amounts drawn were already included in base rates. He testified that by not providing a detailed cost breakdown, it is difficult and problematic to track the use and movement of contingency funds or any other future project cost components. Therefore, Mr. Alvarez suggests Petitioner provide a detailed cost breakdown and critical cost component information for each project included in its CCR closure plan in its ECR tracker going forward. Mr. Alvarez testified that as Petitioner's existing semi-annual ECR tracker will be used to recover CCR closure costs, the Commission should order Petitioner to report cost details and up-to-date project management reports in future coal ash compliance filings. He testified that Petitioner should provide all project management reports generated monthly, quarterly, and annually within the appropriate period of each filing up to the designated cut-off date for the period. In addition, Petitioner should identify the reports in which changes to projects scopes, schedules, costs, etc., occurred and provide the relevant weekly reports in which such changes were reported. He testified that Petitioner should also expand the cost information provided in Petitioner's Exhibit 2-L (TJT) to include detailed cost information (such as project contingency amounts and calculations) and a breakdown of the cost types (direct, indirect, and overhead costs) and associated components of each cost type.

6. Petitioner's Rebuttal Testimony. In rebuttal, Mr. Schwartz testified that while it is possible that subsequent corrective action might be required after initial closure in-place, the

Company has appropriately considered this contingency and the closure plan approvals and existing IDEM regulations provide a framework to address such situations. It is also unlikely and pure speculation by Ms. Armstrong that closure-in-place costs plus additional corrective action costs end up exceeding the estimated costs for a closure-by-removal plan. It is also incorrect to assume closure-by-removal would eliminate the need for corrective action. He testified that based upon the Company's evaluation of the data and environmental information for the sites, it is not anticipated that any subsequent corrective action costs that are reasonably foreseeable (even when added to the in-place closure costs) would exceed the costs of closing the ash ponds at issue by removal.

Mr. Schwartz explained the Company's coal ash closure and compliance obligations under Indiana's Solid Waste Regulations and how the Company conducted environmental audits related to the Gibson East Ash Pond and the historic ash management areas at the former Dresser Station and Noblesville Station pursuant to Indiana's Environmental Audit Program. He testified that the Company voluntarily disclosed the results of its environmental investigations to IDEM, which has cooperatively worked with the Company on closure activities to manage ash management areas in a manner protective of human health and the environment. Mr. Schwartz testified that an IDEM Agreed Order was the best way to facilitate the successful closure of its historic ash management areas with defined expectations and timelines for the Company's closure work as well as IDEM approval of the Company's plans and supervision of the work. He testified that an Agreed Order often identifies activities that, in many cases, are required even in the absence of an Agreed Order in which it sets forth mutually acceptable processes to achieve compliance with current requirements and that there is no admission of any alleged legal violation. He testified that Agreed Orders with IDEM are common for a public utility, as they establish settlement terms on various issues, avoid litigation, and identify actions to resolve environmental issues in a manner to comply with legal mandates and protect human health and the environment. He testified that the Company's original actions regarding the placement of the coal ash in these historic ash management areas were lawful at the time, and any Agreed Order civil penalties often relate to IDEM's view regarding the current state of the site. Mr. Schwartz disagreed with Ms. Armstrong's statement that the Agreed Order process provides an incentive for utilities to propose more costly compliance projects. He testified that the Commission should allow the Company to recover its coal ash closure expenses associated with Gibson East Ash Pond, former Dresser Station, and Noblesville because managing coal ash and ultimately closing coal ash impoundments and historic ash management areas in compliance with the state and federal law is part of providing electric service to customers. Mr. Schwartz testified that the Commission should allow the expenses associated with the former Dresser Station and Noblesville, as expenses incurred to comply with a consent decree are recoverable and the Commission has done so in the past. Reaching agreement with state environmental regulators was a prudent and reasonable way to resolve potential environmental concerns with its historic ash management areas and provides a good vehicle for the Company to define, clarify and complete its mandated closure activities. Mr. Schwartz testified that it would be poor public policy to thwart the goals of IDEM's environmental audit and voluntary disclosure policies by disallowing all costs associated with these coal ash area closure activities. It would also discourage entities from voluntarily investigating and disclosing the existence of legacy coal ash areas or other environmental situations that may need to be addressed.

Mr. Schwartz testified that it is illogical for Ms. Armstrong to contend that if closure costs associated with historic ash management areas referenced in Agreed Orders are approved, then in-place closure costs for other ash impoundments should be disapproved, as these recovery costs are not linked or dependent on each other. He testified that each closure plan rises or falls based upon its own merit and the closure plan costs are either prudent and reasonable or they are not. Mr. Schwartz testified that the Company's closure plans are prudent and reasonable. He also testified that Ms. Armstrong's comparison of the Company's ash management to an old Commission order on manufactured gas plants is misplaced. Unlike Indiana Gas, Duke Energy Indiana did not knowingly acquire contaminated property and unsuccessfully attempt to obtain indemnification from the seller associated with that contamination. Duke Energy Indiana did not incur liability simply for owning the land under the historic ash management areas, but as part of its years of burning coal to provide service to customers. The MGP plants in question were not used by Indiana Gas to provide service, and therefore the Court found no connection between the costs incurred to manufacture gas and the provision of service to Indiana Gas customers. Mr. Schwartz testified that this is clearly different to Duke Energy Indiana's historic ash management areas which it owned at the time they were generating electricity, continues to own, continues to be involved with the provision of service to Indiana customers, and is used and useful.

Mr. Schwartz testified that Ms. Armstrong's comment that the Company has not attempted to mitigate costs to its customers is incorrect. The Company will beneficially use ash taken from some of its closed-by-removal impoundments to facilitate the in-place closure for other ash impoundments, which reduces costs to customers by (1) reducing costs for transporting and landfilling ash; and (2) reducing closure costs for impoundments closed in-place as it is a more inexpensive substitute for other structural fills. Mr. Schwartz also testified that the Company commits to providing any net proceeds from future insurance claims related to CCR or IDEM Rule compliance to its customers to help mitigate the expenses of closure plans.

In rebuttal, Mr. Thiemann testified that as a result of the disconnect between the Company's internal project progress and financial reports and how it needs to report through the ECR, he suggests the Commission not order the Company to provide its internal monthly, quarterly, and annual reports on its coal ash closure projects as suggested by Mr. Alvarez. He testified that providing these internal reports which track back to 2015, while the expenditures proposed for recovery in this proceeding start in 2019, would cause confusion. Mr. Thiemann suggested the Company use a reporting format that ties back to Petitioner's Exhibit 2-L. Each future ECR would include the information Mr. Alvarez summarized for each generating station and reflect the estimated cost, final expected closure date, and project expense (investment) to date at the time of the report. The ECR testimony would also include the projects' status and activities related to the milestone schedules. Mr. Thiemann provided an example of the additional information the Company proposes to submit with its future ECR filings in Petitioner's Exhibit 5-A. He testified that this proposed reporting would allow the Commission and parties to adequately monitor and understand the projects and their related expenditures as they proceed, and the Company will also provide a report on contingency in each ECR.

In rebuttal, Mr. Raiford explained that the Company has properly recorded an ARO for its coal ash remediation and pond closure costs once those became a legal obligation under state and federal regulations. He explained that the Company determined that the closure of its coal ash basins as a result of compliance requirements triggered a requirement for the Company to record an ARO liability under the accounting rules. When the ARO liability was recorded, a corresponding equivalent ARO asset was recorded on the books as part of the cost of the associated asset in the property, plant and equipment accounts. This ARO asset will be depreciated over the remaining estimated plant life. He testified that ASC 980 provides that a utility should capitalize a cost, as a regulatory asset, if it is probable that, through the ratemaking process, there will be a corresponding increase in future revenues. He testified that the Company determined that the costs met the capitalization requirements and deferred into a regulatory asset account the depreciation expense associated with the ARO. Mr. Raiford explained that as actual costs are incurred to comply with the federal and state regulations that gave rise to the AROs, the Company reduces the ARO liability to reflect cash spent to satisfy those legal obligations. Simultaneously, it records an entry to reduce the regulatory asset and increase a separate regulatory asset that was created for the purpose of tracking the amount of actual cash expenditures incurred. In addition, the Company transferred the cumulative balance of coal ash related cost of removal amounts collected from customers from the accumulated depreciation reserve to this regulatory asset, so that customers receive credit for the coal ash remediation costs they have already paid. He testified that if the Company were not legally obligated to incur these costs, they would have been recorded as costs of removal. Mr. Raiford testified that Mr. Blakley is incorrect that the Company chose to treat its coal ash closure activities and expenditures qualified as ARO under GAAP. Due to the net ARO asset balance being excluded from rate base, when spend is incurred Duke Energy Indiana utilizes a separate regulatory asset to record coal ash removal cost expenditures on its books to settle its legal obligations, which is the basis for the spend requested to be recovered. Mr. Raiford testified that other utilities have also recorded AROs related to coal ash closure costs, in accordance with GAAP and FERC accounting rules. Mr. Raiford testified that neither GAAP nor FERC rules prohibit recording an ARO if the legal obligation involves the retirement of an asset, such as coal ash surface impoundments. He further testified that the Company has complied with appropriate accounting rules and guidance in its treatment of coal ash closure-related expenditures, as supported by its external annual audit.

In rebuttal, Mr. Davey disagreed with Mr. Blakley's conclusion that the Company chose ARO accounting instead of traditional accounting, testifying that once the expenditures became a legal obligation under the CCR, federal and IDEM rules and IDEM Agreed Orders, the accounting rules required the use of ARO accounting. Mr. Davey also testified that the estimated expenditures from this proceeding would be charged to a regulatory asset and both traditional and federal mandate ratemaking allows a return of and on regulatory assets made up of these types of expenditures. He testified that if the expenditures were not required to be treated as ARO under accounting guidelines, traditional ratemaking would use FERC account 108 (accumulated depreciation), which would result in higher rate base which would similarly receive both a return of and return on. Rate base includes both regulatory assets and accumulated depreciation and the two different forms of accounting/ratemaking end with the same economic result for the Company and its customers. Mr. Davey testified that the Commission's Order in Cause No. 45253 found the Company's coal ash closure costs were recoverable, with a "return on" under traditional ratemaking, and the Federal Mandate Statute provided collateral support for the decision. He testified that a denial of a "return on" coal ash removal costs could have adverse impacts to the Company's credit ratings.

Depreciation expense associated with the estimated total future ARO legal obligations, associated fixed assets and associated regulatory assets are not part of this sub-docket, nor were they included as a revenue requirement in Cause No. 45253. Mr. Davey disagreed with Mr. Blakley's recommendation to deny the Company's request to defer costs exceeding the Company's estimate by more than 25% and to deny carrying costs on any such deferral. He testified that if actual costs exceed the estimate by more than 25%, the Company is requesting to defer them on its books in order to request recovery in a future rate case proceeding, as provided for in the Federal Mandate Statute. Should these costs be subsequently approved as federally mandated by the Commission, then they and their associated financing costs would be eligible for recovery at that time. He testified that the statute does not state actual costs excluding financing costs. Therefore, the definition of costs, including financing costs, is appropriate for the Company to request in its next general rate case.

7. Commission Discussion and Findings.

A. Certificate of Public Convenience and Necessity for Duke Energy Indiana's Compliance Projects. Before granting Duke Energy Indiana a certificate of public convenience and necessity under Indiana Code ch. 8-1-8.4, we must (1) find that public convenience and necessity will be served by the proposed compliance projects, (2) approve the costs associated with the projects, and (3) make a finding on each of the factors in Indiana Code § 8-1-8.4-6(b). Those factors are:

> (A) A description of the federally mandated requirements … that the energy utility seeks to comply with through the proposed compliance project.
> (B) A description of the projected federally mandated costs associated with the proposed compliance project …
> (C) A description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements described by the energy utility under clause (A).
> (D) Alternative plans that demonstrate that the proposed compliance project is reasonable and necessary.
> (E) Information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension.

Indiana Code § 8-1-8.4-6(b).

i. Federally Mandated Requirements. Indiana Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with … any other law, order, or regulation administered or issued by the United States Environmental Protection Agency …." Messrs. Schwartz and Thiemann testified that the Company's closure and post-closure activities are federally mandated requirements under Indiana Code § 8-1-8.4-5. (Schwartz Direct at pp. 14-15; Schwartz Rebuttal at pp. 10-13; Thiemann Direct pp. 24-25). The OUCC agrees that the CCR closure activities are federally mandated but disagrees that closure costs related to historic ash management areas overseen by IDEM are federally mandated. (Armstrong Direct at pp. 7, 9-17).

Duke Energy Indiana witness, Mr. Schwartz explained in both Cause No. 45253 and this subdocket, that in addition to federal CCR Rule requirements, the Company also has coal ash Closure, post-closure and other compliance obligations under Indiana's Solid Waste Regulations. For example, for coal ash surface impoundments that are not subject to the CCR Rule, IDEM reviews and approves closure plans pursuant to Indiana's solid waste disposal regulations (329 Ind. Admin. Code 10-3-1(9)) and IDEM's "Surface Impoundment Closure Guidance." (Schwartz Rebuttal, pp. 4). Mr. Schwartz also explained that in 2016, the Indiana Environmental Rules Board adopted an emergency rule incorporating the CCR Rule requirements into the Indiana Administrative Code, and in 2017, adopted an amendment to Indiana's Solid Waste Management Plan describing IDEM's plan to update Indiana's regulations for regulating CCR disposal facilities to standards equivalent to the EPA's CCR Rule. (Schwartz Direct, p. 5). Mr. Schwartz further testified that Indiana's solid waste management laws are part of a federally mandated and federally approved "solid waste management plan" that was required pursuant to a U.S. Congressional Act—the federal RCRA. (Schwartz Direct, p. 10).

We previously approved the Company's CCR and IDEM-mandated coal ash closure costs in Cause No. 45253, stating that the CCR and IDEM Project costs "will provide longstanding benefits, in terms of compliance with such federal and state mandates, improved environmental footprints, and the ability to continue to use utility properties," and that "important to our decision is that we have consistently allowed recovery of environmental compliance costs generally and coal ash related compliance costs in particular. See for example, our Orders in Cause Nos. 44765, 44794, 45052, and 44872." Cause No. 45253 Order at 48. Furthermore, IDEM has asserted jurisdiction over all coal ash closure, post-closure and compliance obligations in the State of Indiana. As such, we believe it appropriate to treat the Company's coal ash closure and compliance obligations presented in this proceeding as undertaken for purposes of direct or indirect compliance with the federally mandated requirements of the federal RCRA. In accordance with the policy of encouraging environmental rule compliance, and in light of the definition of "compliance project" in Indiana Code § 8-1-8.4-2(a), which specifically includes projects "related to direct or indirect compliance" with federally mandated requirements, we find that all of the Company's closure and post-closure compliance projects in this proceeding are federally mandated requirements under Indiana Code § 8-1-8.4-5.

ii. Federally Mandated Project Costs. Indiana Code § 8-1-8.4-4(a) defines federally mandated costs as "costs that an energy utility incurs in connection with a compliance project, including capital, operating, maintenance, depreciation, tax, or financial costs." Mr. Thiemann testified that Petitioner's cost estimate is approximately $337 million through 2028 for those basins already approved by IDEM (unescalated and after subtracting cost of removal), with more details shown in Petitioner's Confidential Exhibit 2-L. (Thiemann Direct, pp. 21-22). No party took issue with the projected cost estimates in this proceeding. The Commission agrees that the Company's cost estimate represents a reasonable cost estimate for the closure, post-closure, and other coal ash related compliance projects in this proceeding. Based on the evidence presented, we approve the projected federally mandated costs and expenses associated with the closure, post-closure and other coal ash related compliance projects as required by Indiana Code § 8-1-8.4-6(b)(1)(B).

iii. Compliance Projects. Mr. Thiemann testified that Petitioner's closure, post-closure and coal ash compliance projects have been reviewed and approved by IDEM. (Thiemann Direct, p. 3). As discussed above, we understand that IDEM has adopted the federal CCR Rule as part of its own Solid Waste Management Rules, and that those rules were promulgated in order for Indiana to comply with RCRA. Based on the evidence presented, we find that Petitioner's compliance projects, as approved by IDEM, will allow it to comply directly or indirectly with RCRA. Therefore, we find that Petitioner has satisfied the requirements of Indiana Code § 8-1-8.4-6(b)(1)(C).

iv. Alternative Plans. Mr. Thiemann testified that the IDEM Surface Impoundment Guidelines provide two basic types of closure methods: 1) Clean Closure, and 2) Closure in Place. (Thiemann Direct, p. 20). Mr. Thiemann also explained that each site-specific closure option is included in the closure plan documents and the chosen option is listed for each basin in the Closure Plan narrative. As the plans were developed, each ash management area was reviewed for the best and most cost-effective way to comply with the federal CCR requirements. However, even though the Company has explained which method of closure it has proposed to IDEM – truly, the only "alternative" that Duke Energy Indiana may use to close its surface impoundments is the alternative that IDEM has approved. (Thiemann Direct, pp. 20-21). Therefore, based on the evidence presented, we find that Petitioner considered alternative plans for compliance and that the proposed compliance projects are reasonable and necessary. Therefore, we find that Petitioner has satisfied the requirements of Indiana Code § 8-1-8.4-6(b)(1)(D).

v. Useful Life of the Facilities. Mr. Thiemann explained that for the generating sites Duke Energy Indiana plans to continue to operate, there are compliance activities necessary for continued operation, such as loading, hauling and placement of ash and fixated material in the operating landfills, as well as landfill management. The closure of a basin at a particular site does not, however, extend the useful life of the generating facility. (Thiemann Direct, p. 21). We understand the nature of these federally mandated requirements do not necessarily extend the useful life of a facility, but still must be performed in order to remain in compliance. Therefore, we find the Company has provided us with information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility in accordance with Indiana Code § 8-1-8.4-6(b)(1)(E).

vi. Conclusion. The evidence presented demonstrates that the proposed compliance projects will allow Petitioner to comply with federally mandated requirements. As discussed above, we have made a finding on each of the factors described in Indiana Code § 8-1-8.4-6(b) and approve the projected federally mandated costs associated with the Company's closure and coal ash related compliance projects. Therefore, we approve the proposed compliance projects and issue Duke Energy Indiana a certificate of public convenience and necessity for its proposed compliance projects under Indiana Code § 8-1-8.4-7(b).

In addition, we note that the Company originally requested recovery of these costs through its base rate case, Cause No. 45253, and that we ordered the Company to instead address the costs associated with these compliance projects in this subdocket. As we stated in our order in Cause No. 45253, and it bears restating here, the closure, post-closure and other coal ash related compliance projects at issue in this subdocket are the types of costs recoverable under either traditional ratemaking (as was the treatment granted in the rate case) or under the Federal Mandate Statute (as we are approving here). These closure, post-closure and other coal ash related compliance projects could have been reflected in costs of removal and depreciation rates and recoverable in that manner in the Company's base rate case. The Commission wanted the additional review of the proposed compliance projects in this subdocket, and finds these costs appropriate to recover through rates.

B. **<u>Cost Recovery</u>.** Indiana Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
>
> (1) 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. The commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3) and IC 8-1-2-42(g)(3).
>
> (2) Twenty 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.
>
> (3) Actual 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.

Because the Company's closure, post-closure and coal ash related compliance projects are for direct or indirect compliance with federal mandates, as discussed above, and the federally mandated costs are associated with the proposed compliance projects, the Commission finds that Duke Energy Indiana is authorized to recover 80% of its approved costs through Standard Contract Rider No. 62. In addition, Duke Energy Indiana is authorized to defer 20% of the approved costs until its next general rate case. Furthermore, Duke Energy Indiana is authorized to recover 80% of its costs associated with the compliance projects through Standard Contract Rider No. 62 with 20% deferred until Petitioner's next general rate case. Recovery through Standard Contract Rider No. 62 shall be consistent with the Company's proposal in this proceeding as outlined in the testimony of Mr. Davey.

C. **<u>Insurance Proceeds and Reporting Requirements</u>.** The OUCC recommended offsetting the overall closure costs with insurance proceeds Duke Energy Indiana receives related to ash pond remediation. The OUCC stated Duke Energy Indiana should provide regular status updates on insurance claims, detailed cost information and updated project management reports in ECR filings. Duke Energy Indiana noted that it preserved its rights in 2016 relating to the insurance proceeds by giving notice of future claims to its insurance carriers. Duke Energy Indiana is evaluating its available coverage and the potential for recovery under the policies. Duke Energy Indiana committed to providing any net proceeds from future claims related to CCR Rule or IDEM Rule compliance to its customers to help mitigate the closure plan expenses. We agree with the OUCC that Duke Energy Indiana should provide regular status updates on insurance claims, detailed cost information and updated project management reports in ECR filings.

8. Confidential Information. Duke Energy Indiana filed a Motion for Protection of Confidential and Proprietary Information ("Confidential Information"), which was granted on a preliminary basis. We find that all such information should continue to be held confidential pursuant to Indiana Code § 8-1-2-29, Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2.

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

1. Duke Energy Indiana's proposed closure, post-closure and coal ash related compliance projects detailed in the testimony in this proceeding constitute "federally mandated compliance projects" as defined by Indiana Code § 8-1-8.4-2.

2. Duke Energy Indiana is issued a Certificate of Public Convenience and Necessity for the compliance projects pursuant to Indiana Code §§ 8-1-8.4-6 and -7. This Order constitutes the Certificate.

3. Duke Energy Indiana is authorized to recover its compliance-related costs presented in this proceeding through rider recovery and deferral treatment.

4. Duke Energy Indiana is authorized to recover 80% of its federally mandated costs, including carrying costs, through Petitioner's Standard Contract Rider No. 62. Petitioner is authorized to defer the remaining 20% of its federally mandated costs until Petitioner's next general rate case.

5. The Confidential Information shall continue to be exempt from disclosure under Indiana Code § 8-1-2-29, Indiana Code § 24-2-3-2, and Indiana Code § 5-14-3-4.

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

<u>FREEMAN, HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR:</u>

APPROVED: NOV 03 2021

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: 2021.11.03 10:34:19
-04'00'

Dana Kosco
Secretary of the Commission