Cause No. 46038

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF SEAN P. RILEY

Petitioner's Exhibit 13

April 4, 2024

DIRECT TESTIMONY OF SEAN P. RILEY
PARTNER, PRICEWATERHOUSECOOPERS LLP
ON BEHALF OF DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. My name is Sean P. Riley. I am a partner with PricewaterhouseCoopers LLP ("PwC"). My business address is PricewaterhouseCoopers LLP, 101 Seaport Boulevard, Boston, Massachusetts 02210.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony before the Indiana Utility Regulatory Commission ("Commission") on behalf of Duke Energy Indiana, LLC. ("Duke Energy Indiana" or the "Company").[1]

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I graduated from the University of Vermont in 1990 and was hired by Coopers & Lybrand (predecessor company to PwC) in 1992 as an auditor focused on the financial statement audits of regulated utilities. PwC is the largest professional services network in the world, providing audit, tax, and advisory services to the largest and most complex companies globally. I was admitted to the partnership of PwC in 2004. I am a certified public accountant ("CPA") currently licensed in the States of Maine and Massachusetts.

[1] This testimony was prepared by Sean P. Riley in connection with the current Duke Energy Indiana rate case and for the use and benefit of Duke Energy Indiana. PricewaterhouseCoopers LLP disclaims any contractual or other responsibility to others based on their access to or use of this direct testimony and the information contained herein.

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I am a member of PwC's National Energy, Utility and Resources ("Utility") practice. Our nationally recognized practice is viewed as a leader in the utilities sector, and comprises over 1,300 professionals, including professionals experienced in serving rate-regulated entities. We serve all of the largest and most complex regulated utilities in the United States. I currently have two roles within our Utility practice. First, I am an Assurance Partner leading significant financial statement and internal controls over financial reporting audit engagements in the utility sector. In addition, I lead PwC's Complex Accounting and Regulatory Solutions ("CARS") practice. In this role, I oversee a team of highly experienced utility sector specialists that advise clients on complex technical accounting and regulatory/ratemaking matters. In addition, our CARS team is responsible for the development of thought leadership related to the utility sector. I previously completed a three-year tour as the Utility and Renewable Energy technical accounting leader in the Accounting Services Group within PwC's National Office. I have been a frequent speaker at PwC utility industry events, as well as for organizations such as the Edison Electric Institute ("EEI") and American Gas Association ("AGA").

Q. HAVE YOU DEALT WITH THE UNIQUE ACCOUNTING AND FINANCIAL REPORTING ISSUES ENCOUNTERED BY REGULATED ENTERPRISES?

A. Yes. Throughout my career, I have focused on utility accounting and regulatory/ratemaking issues primarily as a result of auditing regulated enterprises. The unique, Generally

Accepted Accounting Principles ("GAAP") applicable to regulated entities embodied in Accounting Standard Codification ("ASC") 980 *Regulated Operations* ("ASC 980") (previously known as Statement of Financial Accounting Standard ("SFAS") 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS 71") and related standards all need to be understood so that auditors can determine if a company's accounting has been applied appropriately. It is also necessary to have a solid understanding of the concepts of ratemaking (i.e., how rates are established for various classes of ratepayers and how utilities are paid for the services they provide) for regulated utilities in order to ensure that a company's accounting is in accordance with GAAP. During my career, I have advised regulated utilities, and internally with other PwC professionals, as to how these ratemaking concepts and related accounting standards should be applied.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS OR ANY OTHER COMMISSION?

A. Yes. I have provided testimony in North Carolina and South Carolina for the Duke Energy Carolinas and Duke Energy Progress utilities. I have also provided testimony across the United States, including Connecticut, Massachusetts, Missouri, and Hawaii, as well as various matters before the Federal Energy Regulatory Commission ("FERC").

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

A. My testimony will address Duke Energy Indiana's treatment of Coal Combustion Residuals (CCR, or coal ash) closure and management costs, and why it is appropriate to permit recovery of such amounts from customers. CCR costs are a required cost to appropriately handle coal ash in compliance with state and federal regulations upon the retirement of coal generating facilities. The ratemaking process traditionally allows for recovery of and return on investor funds needed to construct/acquire Property, Plant and Equipment ("PP&E"), as well as the funding of the net cost to retire/remove the PP&E from service at the end of its useful life.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. In my testimony I will:

- Explain the accounting from both a GAAP perspective, as well as the accounting required by the FERC Uniform System of Accounts ("USoA").[2]
- Discuss the ratemaking process and how that process impacts the accounting for rate-regulated utilities (such as Duke Energy Indiana) under ASC 980.
- Discuss the accounting and ratemaking treatment of post-retirement costs driven by specific legal obligations ("legal obligations") and post-retirement costs driven by operations in the normal course of business ("non-legal postretirement obligations"), often called "cost of removal."
- Discuss Coal Ash closure costs (what they are, how they are accounted for and how they are appropriately treated as a recoverable cost in this rate filing).

[2] The currently effective version of the FERC USoA is codified at 18 C.F.R. part 101.

II. ACCOUNTING FOR PROPERTY, PLANT AND EQUIPMENT

Q. CAN YOU PLEASE DISCUSS HOW A CAPITAL-INTENSIVE COMPANY TRADITIONALLY ACCOUNTS FOR INVESTMENT IN PP&E?

A. Yes. Capital-intensive companies require significant investment in PP&E. Amounts are initially capitalized in the company's books and records at the original cost of the PP&E constructed or acquired.

Once placed in service, the PP&E is depreciated over its estimated useful life. The concept of depreciation allocates the cost of the PP&E to the periods in which it is used to provide service to customers. The sum of each year's annual depreciation expense is recorded in Accumulated Depreciation. The original cost and accumulated depreciation are presented on the balance sheet, with the "net" amount representing the unrecovered cost of PP&E.

When the PP&E reaches the end of its life, the PP&E and Accumulated Depreciation amounts are removed from the books and records and the asset is retired.

Q. WHAT HAPPENS WITH AMOUNTS EXPECTED TO BE RECEIVED UPON RETIREMENT (SALVAGE) OF PP&E?

A. Depreciation charges consider the estimated salvage values when determining the annual depreciation charge. Under the Financial Accounting Standards Board ("FASB") Accounting Standards Codification, the FASB ASC paragraph 360-10-35-4 [Property, Plant and Equipment-Overall-Subsequent Measurement-Depreciation] defines depreciation as:

> *The cost of a productive facility is one of the costs of the services it renders during its useful economic life. Generally accepted accounting principles (GAAP) require that this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility. This procedure is known as depreciation accounting, a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.*

Q. YOU EXPLAINED HOW SALVAGE COSTS IMPACT DEPRECIATION CHARGES. WHAT IF THERE IS A COST TO RETIRE THE PP&E?

A. In many cases, at the end of a fixed asset's life, a company incurs a cost to remove, dispose, or otherwise permanently retire an asset from service. Under GAAP, the accounting for such "end of useful life" costs depends on whether the cost to retire the PP&E is a legal obligation or not. If the cost is a legal obligation, the accounting is governed by ASC 410 Accounting Retirement Obligations ("ARO"). If the cost to retire is not a legal obligation, the retirement cost falls under cost of removal accounting. I will discuss both of these concepts from a

GAAP accounting, FERC accounting and ratemaking perspective later as this is the key focus of my testimony.

Q. CAN YOU GIVE AN EXAMPLE OF ACCOUNTING FOR PP&E?

A. Yes. Assume a company constructs or acquires PP&E for a cost of $1 million. Assume the PP&E has a five-year life and upon retirement the company will receive $50,000 of salvage proceeds. In this example, the company will calculate an annual depreciation charge of $190,000 (calculated as the plant cost of $1 million minus $50,000 of salvage cost, allocated over a five-year period, producing an annual depreciation expense of $190,000). The journal entries are as follows:

PP&E	$1 million	
Cash		$1 million
(To record the construction/acquisition of the fixed asset)		
Depreciation Expense	$190,000	
Accumulated Depreciation		$190,000
(To record depreciation expense in each year one to five)		
Cash		$50,000
Accumulated Depreciation	$950,000	
PP&E		$1,000,000
(End of life; recognize salvage proceeds and retire the PP&E)		

As can be seen in this simple example above, depreciation accounting contemplates allocating the net original cost of the fixed asset (cost of the fixed asset reduced by the estimated salvage value) over its estimated useful life. The net cost is allocated over the estimated useful life of the fixed asset and each period incurs an appropriate depreciation charge. Finally, it is also important to note that, in practice, the actual cost of salvage will change from the original amount estimated at the beginning of the accounting cycle; consequently, adjustments to the accounting will occur (at the time that management determines that the salvage cost changes are known and measurable). Such adjustments will be treated on a prospective basis as a "change in estimate."

Q. DOES DUKE ENERGY INDIANA FOLLOW GAAP ACCOUNTING?

A. Duke Energy Indiana follows GAAP for external financial reporting purposes. For regulatory purposes, the Company follows the FERC USoA.

Q. ARE THE TWO ACCOUNTING SYSTEMS SIMILAR?

A. Yes, the two systems are similar, but there are differences to recognize the economic consequences of the unique ratemaking process.

III. <u>THE RATEMAKING PROCESS AND ASC 980</u>

Q. PLEASE EXPLAIN HOW THE RATEMAKING PROCESS IMPACTS ACCOUNTING.

A. Under traditional rate regulation for investor-owned utilities, the prices charged for services provided by utilities (electric, gas and water entities) are regulated (subject to review and approval) by a state's regulatory commission (such as the Indiana Utility Regulatory Commission or "IURC") and/or the FERC, as applicable. This is because such entities provide a necessary service and operate as monopolies. Without such regulation, the monopoly utility could charge whatever it could, and would therefore potentially earn "super-monopoly" profits. Instead, the regulatory compact permits the utility to operate in a specific service territory and, in return, the regulatory commission regulates various aspects of the utility, including pricing.

In return for being granted an exclusive service territory, the regulator (in this case, the IURC) sets the prices Duke Energy Indiana can charge for electric service. The prices (base rates) are determined in a rate case where the Company presents its cost of service, consisting of a return on rate base plus recovery of the operating costs of providing such service. The rate base is primarily the unrecovered costs of fixed assets. The return is the annual debt and equity costs required by investors for their investment in the utility. Operating expenses are operating and maintenance costs, depreciation, taxes other than income and income taxes necessary to provide service to customers. The cost of service determined in a rate case is the revenue requirement from which a tariff is produced.

Q. HOW DOES RATE REGULATION IMPACT GAAP?

A. In the ratemaking process, the regulator can decide to permit recovery of a cost in a period that is different from when GAAP would require such cost to be reported. For enterprises in general, there is no direct link between expenses and revenues. For such enterprises, revenues/prices are based on what the market will bear. Because rate-regulated utilities are not subject to competition, the regulator acts as a substitute for competition and requires rate cases for the utility to present its costs for the development of its revenue requirement (prices). Under this unique rate-regulation mechanism, there is a matching of revenues and costs that should be reflected in the utility's financial statements. This is accomplished via ASC 980, which includes the concepts initially included in SFAS 71.

Q. WHAT IS ASC 980 AND ITS PREDECESSOR STATEMENT SFAS 71?

A. SFAS 71 was issued by the FASB in 1982. This Statement was the primary accounting principle providing accounting guidance for rate-regulated entities and addressed the unique accounting for entities where a clear linkage exists between rates or tariffs charged to customers and a rate-regulated company's cost. A rate-regulated enterprise's costs include both necessary operating expenses and an allowed return (representing the cost of capital, both debt and equity).

Under SFAS 71, utilities are required to defer, as regulatory assets, incurred costs that non-regulated entities would charge to expense if, as a result of the regulatory process, it is probable that such costs will be recovered in future charges to ratepayers. Additionally, rate-regulated entities are required to record regulatory liabilities when it becomes probable that a regulator will require the refund of revenues previously charged to and collected from ratepayers. The FASB codified the concepts of SFAS 71 within ASC 980 in September of 2009.

Q. GENERALLY, WHICH TYPES OF ENTITIES FOLLOW THE ACCOUNTING UNDER ASC 980?

A. Historically, rate-regulated electric, gas and water utilities, where revenues are based on costs determined in a rate case, follow the accounting requirements of ASC 980. Duke Energy Indiana is such a company. The economic effects of regulation were considered unique by the FASB when they considered the accounting that eventually resulted in ASC 980.

SFAS 71 as originally issued noted:

> *"This Statement may require that a cost be accounted for in a different manner from that required by another authoritative pronouncement. In that case, this Statement is to be followed because it reflects the economic effects of the rate-making process—effects not considered in other authoritative pronouncements. All other provisions of that other authoritative pronouncement apply to the regulated enterprise."*

The ratemaking process provides a linkage between costs and revenues, creating an economic effect which is reflected in GAAP financial statements for rate-regulated entities. ASC 980 has been in effect for many years, and the concept of regulatory assets and regulatory liabilities is not a new one. If the conditions of ASC 980 are met, regulated entities will recognize a regulatory asset or liability whenever expenses or revenues are recognized in one period for regulated ratemaking but would have been recognized in another period under GAAP for an unregulated entity. The important point here is that the GAAP accounting for rate-regulated utilities follows the ratemaking process to reflect the unique, economic consequences of rate regulation.

Q. ARE THERE DIFFERENCES BETWEEN GAAP AND FERC USOA IN THE AREA OF PP&E?

A. Yes. While the basic accounting for the cost of PP&E, depreciation and salvage are generally the same, there are differences that relate primarily to the costs that will be necessary to remove or remediate a facility in connection with retirement or closure. The reason for such differences is the need for the books and records to support the equitable allocation of removal/remediation costs to customers who benefitted from the operation of such assets in the ratemaking process. I explain these differences later in my testimony.

Q. HOW ARE UTILITY INVESTORS COMPENSATED FOR THEIR INVESTMENT IN PP&E?

A. Under traditional regulation, investors are the typical source of PP&E investment (costs to acquire or construct the infrastructure needed to provide generation, transmission, or distribution service to customers). Once an asset is placed in service, it is depreciated, typically on a straight-line basis, over the estimated useful life of the fixed asset. Depreciation expense is recorded and included in the rate case as the mechanism to charge customers for the estimated annual cost of the investment in PP&E used to generate/transmit/distribute electricity, while at the same time recovering this amount from customers to return funds to the investors. The net unrecovered investment in PP&E is included in rate base and earns the rate of return. In this manner, the investor is returned their capital and continues to earn on the unrecovered investment until it is recovered.

Q. CAN YOU EXPLAIN THE CONCEPT OF "RECOVERY OF" AND "RETURN ON" THAT IS OFTEN CITED IN THE RATEMAKING PROCESS?

A. Yes. Simply stated, recovery of the investment means the investor receives full cost recovery of each dollar invested. An investment in a generating facility, for example, requires capital investment on the front end to acquire or construct the facility. The investor recovers their investment as the plant is depreciated and the customers pay the revenue requirement (which includes recovery of depreciation expense). However, as the investor has supplied the funds for investment in the plant in advance of recovering such investment, they are also entitled to a return on their investment related to the time value of money, opportunity cost and risk associated with that investment. Therefore, the undepreciated cost (i.e., remaining net book value) of the plant is included within rate base and earns an allowed return. In this manner, over the asset's life, the investor receives their money back and earns a return on their investment until fully recovered.

IV. PP&E POSTRETIREMENT COSTS

Q. YOU PREVIOUSLY DESCRIBED THE ACCOUNTING AND RATEMAKING LIFECYCLE FOR PP&E ASSUMING SALVAGE PROCEEDS ARE RECEIVED UPON RETIREMENT OF THE PP&E. CAN YOU NOW TURN TO THE ACCOUNTING AND RATEMAKING TREATMENT OF THE COSTS INCURRED TO RETIRE OR REMOVE THE PP&E?

A. Yes. Removal costs are the costs incurred at the end of an asset's useful life. At that time, there may be a salvage value (as I previously described), removal cost, or both. Salvage value is the amount realized from selling parts (such as scrap metal or poles) resulting from dismantling a fixed asset. As opposed to salvage, there are often costs incurred to physically remove assets from service upon retirement, safely dispose of the asset and/or restore the site, which are referred to as removal costs (or sometimes referred to as "negative salvage").

Certain of these removal costs represent legal obligations. For example, certain sites contain asbestos or other regulated substances. There are environmental laws that govern the removal of asbestos or other regulated substances when the facility is retired, each of which comes with a cost. On the other hand, certain removal costs are not legally required but are incurred for other reasons. For example, when utility poles are retired, they are physically removed from service although there is generally no legal obligation to do so.

The distinction between legal and non-legal removal costs affects the GAAP accounting.

Q. DOES GAAP PROVIDE FOR RECOGNIZING THE COST OF REMOVAL OR NEGATIVE SALVAGE FOR NON-LEGAL OBLIGATIONS BEFORE SUCH REMOVAL/RETIREMENT AMOUNTS ARE PAID?

A. No. GAAP does not have any standard that requires the cost of removal to be recorded for non-legal removal obligations prior to the removal being performed. Under GAAP, enterprises in general (outside of rate-regulated utilities such as Duke Energy Indiana) expense non-legal retirement costs when incurred.

Q. YOU SAID THE COST OF REMOVAL CONCEPT DOES NOT EXIST IN GAAP. DOES THE FERC USOA CONTAIN A DEFINITION AND PROVIDE ACCOUNTING GUIDANCE FOR COST OF REMOVAL?

A. Yes. The FERC USoA defines cost of removal as follows:

> *"Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto…"*

Regulators, including FERC, permit the costs of removal to be recovered from customers through annual depreciation charges. Cost of removal operates in the opposite manner as salvage value; rather than recording a reduction in depreciation expense to consider estimated salvage proceeds, the estimated cost of removal is added to the depreciation expense each period. As such, cost of removal is often referred to as "negative salvage."

Q. WHAT IS THE REASON FOR INCLUDING A COST OF REMOVAL/NEGATIVE SALVAGE COMPONENT IN DEPRECIATION RATES?

A. Including a net salvage component in depreciation rates results in a proper cost allocation and intergenerational equity. I will describe cost of removal accounting using the same example I used to describe the accounting for salvage by simply changing the $50,000 salvage amount used in that example to $50,000 for removal costs. The cost of removal example assumes a $1 million PP&E addition, a five-year life and $50,000 in estimated cost be incurred to retire the $1 million asset at the end of its life. Thus, in this example, annual depreciation expense of $210,000 is required to allocate the plant basis plus retirement cost (total cost of $1,050,000) over the useful life of the PP&E. Without the inclusion of the $50,000 expected to be incurred to retire the assets, the company will not be made whole for all of its prudently incurred costs, the equitable cost allocation will not occur, and customers who have use of the asset and benefit from that use will not pay the full cost of such assets.

From an accounting standpoint, the additional depreciation charges each year are credited to Accumulated Depreciation. Accumulated Depreciation reduces gross PP&E amounts when determining rate base. As such, customers who pay rates that recover depreciation expense receive the benefit of that recovery through lower net original cost rate base.

Q. CAN YOU SHOW THE JOURNAL ENTRIES TO RECORD THE ABOVE EXAMPLE?

A. Yes.

Entry 1:	PP&E	$1,000,000	
	Cash		$1,000,000
	(To record the construction/acquisition of PP&E)		
Entry 2:	Depreciation Expense	$210,000	
	Accumulated Depreciation		$210,000
	(To record annual depreciation in years 1-5, consisting of $200,000 to recover the cost of the PP&E, plus $10,000 annually for the estimated end of life cost of removal)		

At the end of five years, the balances are:

PP&E (gross)	$1,000,000

	Accumulated Depreciation	$1,050,000	

At this point, assume the asset is retired and $50,000 of cost of removal is incurred.

Entry 3:	Accumulated Depreciation	$50,000	
	Cash		$50,000
	(To record the actual cost of removal incurred)		
Entry 4:	Accumulated Depreciation	$1,000,000	
	PP&E		$1,000,000
	(To record the retirement of the PP&E. The original cost is reduced for the gross amount in the books and records and Accumulated Depreciation is reduced by the same amount).		

In this example, the company has incurred $1,050,000 of PP&E and cost of removal, and such amount has been recovered through depreciation charges.

Q. YOU STATED THAT DEPRECIATION CHARGES, INCLUDING ESTIMATED COST OF REMOVAL, ARE RECORDED IN ACCUMULATED DEPRECIATION REPRESENTING RECOVERY OF THE PP&E ITSELF AS WELL AS ESTIMATED NET SALVAGE. WHAT HAPPENS TO THE ACTUAL NET COSTS EXPENDED TO REMOVE OR NECESSARILY INCURRED UPON RETIREMENT?

A. The actual removal costs incurred are charged to Accumulated Depreciation. FERC USoA Plant Instruction 10 includes the following guidance:

> *"... When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. <u>The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account</u>." (Emphasis added).*

In the above example, $50,000 of removal costs were estimated and included in determining annual depreciation expense. If, instead of the $50,000 estimated cost of removal, the actual cost of removal ultimately was $60,000; in that case, entry three would be $60,000. Entry four would be the same, and there would be a $10,000 debit balance remaining in Accumulated Depreciation (representing the under-recovery of depreciation in this particular example). These over/under of such amounts included in Accumulated Depreciation are taken into account in future depreciation studies and recovered through increases/decreases when determining future depreciation rates. Gains or losses are not separately recorded for such normal retirements; such amounts remain in Accumulated Depreciation and recovered or returned through future depreciation. This is an important point - with the exception of abnormal retirements, the costs of prudently incurred PP&E, including salvage/cost of removal, are recovered in the ratemaking process through depreciation charges. This is why the FERC USOA requirement that actual cost of removal payments be recorded in Accumulated Depreciation is key. This accounting drives the recovery of the trued-up (i.e., estimate to actual) net salvage in future depreciation.

Q. IF COST OF REMOVAL ACCOUNTING IS APPROVED FOR REGULATED ENTITIES, HOW DOES THIS RECONCILE TO GAAP WHERE THE COST OF REMOVAL CONCEPT DOES NOT EXIST?

A. Because regulators have granted recovery of cost of removal over an asset's life for certain assets, the regulator allows entities to include an advanced recovery of removal costs through additional charges to depreciation expense when developing the revenue requirement. As a result, ASC 980 allows regulated entities to recognize this "removal cost depreciation" for these assets for GAAP to offset the revenue being collected to fund the eventual removal cost. However, the amount of cost of removal included in Accumulated Depreciation is reclassified to Regulatory Liabilities for external financial statement presentation purposes.

Q. IF THE REGULATOR ALLOWS FOR THE ADVANCED COLLECTION OF COST OF REMOVAL THROUGH "REMOVAL COST DEPRECIATION," HOW IS THAT ACCOUNTED FOR?

A. As previously noted, there is no GAAP standard that stipulates how "removal cost depreciation" should be accounted for. Rather, ASC 980 matches the "removal cost depreciation" expense with the revenue requirement that considers "removal cost depreciation" as one of the costs of providing service. Please refer to my discussion above for the accounting and financial reporting presentation of cost of removal and depreciation.

While the investor's investment in Property, Plant and Equipment increases rate base, Accumulated Depreciation reflecting the cumulative depreciation expense (both depreciation of the asset itself and removal cost depreciation recovered in advance from customers) reduces rate base until the removal is performed, at which time no incremental expense would be recognized as it was recognized over the asset's life.

Q. IS IT YOUR TESTIMONY THAT UNDER COST OF REMOVAL ACCOUNTING RATE-REGULATED ENTITIES RECOVER ESTIMATED REMOVAL COSTS IN ADVANCE OF WHEN SUCH AMOUNTS ARE ACTUALLY SPENT?

A. It is, with the caveat that cost of removal accounting ultimately represents a model whereby estimated costs will ultimately be trued-up to actual costs incurred (i.e., the ratepayer ultimately pays rates reflecting the actual removal costs). Regulators can approve whatever regulatory treatment they desire within their statutory limits. In the United States, it is common practice for utility commissions to approve a certain level of costs associated with expected future PP&E closure/remediation in advance of such costs being incurred via the cost of removal methodology described above. When actual removal/remediation costs become known and are incurred post closure, such costs are charged (debited if the cost of removal accrual was less than actual costs; credited if the cost of removal accrual was greater than actual costs) to Accumulated Depreciation, and subsequently incorporated in the next depreciation study (with differences between previously recorded estimated removal costs and actual removal costs used to develop the updated depreciation accrual rate and adjusted through future depreciation charges).

Q. CAN YOU SUMMARIZE COST OF REMOVAL ACCOUNTING?

A. Yes. While cost of removal accounting is not specified in GAAP, it is reflected in the GAAP and FERC financial statements as a result of guidance set forth in ASC 980 to mirror the ratemaking approved by a regulator. Under this mechanism, a higher depreciation expense is recognized to match the recovery of future estimated removal costs approved by the regulator. Such amounts are included in accumulated depreciation (for FERC and ratemaking purposes); for financial statement presentation purposes, such amounts are reflected as a regulatory liability (for GAAP non-legal obligations). Regardless of its balance sheet classification, the accumulated removal cost depreciation is included as a reduction to rate base because such amounts have been funded by ratepayers, and therefore ratepayers should receive the benefit of reducing the return on rate base for the amounts that have been recovered through the recovery of depreciation expense (including costs of removal).

Q. YOU HAVE DESCRIBED THE ACCOUNTING FOR PP&E USING THE EXAMPLE OF A SINGLE ASSET. DO UTILITIES SEPARATELY ACCOUNT FOR AND DEPRECIATE EACH ASSET INDIVIDUALLY?

A. No. Most utilities use the "group method" to account for and depreciate PP&E. Under the group concept, assets are grouped into different accounts (structures, poles, generating facilities) and depreciated as a group. Group depreciation is suited to utilities as they typically have a large volume of similar assets. Under the group concept, depreciation is determined and applied to a group of assets, each of which contains assets organized by purpose and identified by retirement unit number and description. Depreciation studies look at the dispersion or pattern of asset retirements around the average life of the group instead of a single asset, resulting in a projection of lives for the group using statistical methods. The assets in the group are depreciated using an estimated average service life of the group and, upon retirement, assets are retired from the accumulated depreciation at full original cost. The assumption is that when an asset is retired, it has achieved the average retirement age for the group. Absent abnormal circumstances, no gain or loss is recognized. The theory is that, on the average, gains and losses for the entire group would cancel each other out.

Q. YOU STATED THAT UNDER GROUP DEPRECIATION, ASSETS ARE DEPRECIATED AS A GROUP. CAN YOU EXPLAIN FURTHER HOW THIS WORKS?

A. Yes. Under group depreciation, PP&E assets are segregated into groups. The USoA has separate property accounts for different functions (production, transmission, distribution) and for different types of assets in those functions (structures, generators, transformers, poles, towers, and fixtures, *et al.*). The USoA requires continuing property records detail such information as the cost, the date placed in service, a description and location. A depreciation study looks at the date a particular asset was placed in service, when it was retired and determines on an actuarial basis, the life. Based on this information, estimates of the lives of the remaining assets in the group are determined and a depreciation accrual rate is determined for the group (an asset with a 10-year life translates into a ten percent depreciation rate. An asset with a 20-year life will produce a five percent depreciation rate). The depreciation rate is applied to the gross asset balance each period with depreciation expense and Accumulated Depreciation recorded. When an asset is retired, the original cost of that asset is removed from service (credit) and the Accumulated Depreciation is reduced (debit). Gains or losses are not recognized for such normal retirements. Any differences between depreciation recorded based on the depreciation study and actual lives/removal costs are captured in Accumulated Depreciation and factored into the next depreciation study for future recovery.

Q. CAN YOU FURTHER DISCUSS WHAT HAPPENS IN SITUATIONS WHERE EITHER THE ACTUAL PP&E LIVES OR ACTUAL AMOUNTS RECEIVED OR INCURRED FOR SALVAGE OR COST OF REMOVAL DIFFER FROM THE ESTIMATES?

A. Due to the long-term nature of infrastructure investment, this is not an uncommon occurrence. Instead of recognizing gains or losses upon retirements of PP&E, depreciation studies are used to "true up" for these differences and carry forward the differences between estimated and actually incurred amounts, i.e. gains/losses, in Accumulated Depreciation to be recovered or credited in future depreciation accruals. It is important to recognize that both depreciation lives, and removal costs used to determine depreciation accruals are estimates, and when actual amounts (lives and amounts) requiring true-up are identified, they are reflected prospectively. Based on actual experience, the estimated service lives can be increased or decreased to reflect, among other things, changes in technology and experience. Actual experience for removal costs and salvage are also considered in the depreciation study and factored in the determination of new depreciation accrual rates/amounts. It is not unusual for changes in estimated lives and removal costs to occur. These are most often not due to errors or omissions; they occur due to the inherent limitations in estimating lives for long-lived assets and other factors that will cause differences from the previous estimates. The important point is that for regulated entities, no more and no less than the prudently incurred costs of PP&E, generally funded by investors, are recovered over time from customers, and investors recover both their capital investment as well as a return on such capital investment until recovery occurs.

In summary, even with periodic depreciation studies, the amount of accumulated depreciation at any point in time prior to the retirement of the property is based on certain life and net salvage characteristics which remain in effect throughout the remaining life of the property. The amount of depreciation that has been accumulated at any date, or between any two dates, must always be an estimate, because the actual facts as to service life, salvage, and cost of removal cannot be known until the property has been retired. Depreciation studies true-up the estimates with differences included in future depreciation accruals.

Q. YOU MENTIONED THAT THERE ARE BOTH LEGAL AND NON-LEGAL REMOVAL COSTS. WHAT ARE THE DIFFERENCES FROM AN ACCOUNTING/RATEMAKING PERSPECTIVE?

A. Under GAAP, the accounting for removal costs that are legally required to be incurred are covered under ASC 410, *Accounting for Retirement Obligations*. I have previously stated that GAAP does not address the accounting for non-legal obligations until such amounts are incurred at which point are expensed (absent ASC 980).

Q. WHAT ARE THE REQUIREMENTS OF ASC 410 UNDER GAAP?

A. ASC 410 became effective in 2003 and requires an entity to determine if it has a present legal obligation to remove, dispose, or remediate an asset. If a legal obligation is present, it is recorded as an Asset Retirement Obligation (ARO) with a corresponding Asset Retirement Cost (ARC). The initial accounting journal entry is as follows:

ARC		$XXX	
	ARO		$XXX

The entity would then depreciate the ARC asset over the underlying asset's economic life and accrete, or increase, the ARO liability through the estimated retirement date, such that when the retirement cost is paid, the ARC asset would have been fully depreciated and the ARO liability would have increased to the amount of the full obligation. Both ARC depreciation expense and ARO accretion expense are recorded on the income statement over time to recognize the estimated costs of settling the legal obligation in the periods that the related asset is being used. As a result, when the underlying asset reaches the end of its useful life, the Asset Retirement Obligation would represent (i.e., be equal to) the cost to settle the obligation at that time.

Q. DOES ASC 410 DEFINE LEGAL AROS?

A. Yes. ASC 410 is the codification of the concepts contained within SFAS 143 *Accounting for Asset Retirement Obligations.* The scope of SFAS 143 included the costs of "legal obligations associated with the retirement of a tangible long-lived asset." Specifically, "The statement applies to costs related to the retirement of a (tangible) long-lived asset resulting from "acquisition, construction, or development and (or) normal operation of a long-lived asset." The definition was interpreted by Financial Interpretation (FIN) 47 *Accounting for Conditional Asset Retirement Obligations - An Interpretation of FASB Statement No. 143* to include "conditional" obligations to remove or dispose of assets.

Common AROs in the electric utility industry include decommissioning of nuclear plants and some coal plants at the end of or after their useful lives, state requirements to safely close ash ponds and costs to remove asbestos from facilities.

The retirement activities for the majority of the utility industry's assets have not been classified as AROs (and do not meet the accounting requirements of ASC 410) because they are not legal obligations (i.e., there is no legal obligation to remove an asset upon retirement). However, this does not mean that removal costs on such assets will not be incurred. GAAP requires that non-legal retirement costs be recognized when incurred, prior to consideration of any ratemaking impacts and the effect of ASC 980.

Q. DOES THE FERC USOA INCLUDE ACCOUNTS FOR AROs?

A. Yes. Since 2003, the FERC USoA has included accounts for ARCs and related depreciation, AROs and related accretion. However, regulators generally ignore ASC 410 for ratemaking purposes due to its "non-cash nature". Neither the ARO liability nor the ARC asset are included within rate base, and ARC depreciation and ARO accretion are excluded from operating expenses for determination of the revenue requirement. While the ARO liability and ARC asset are presented on the balance sheet, they result from accounting journal entries, not investor or customer contributions (and therefore are not considered for ratemaking purposes until the point that actual removal costs are expended upon the retirement of the asset).

FERC provides the following ratemaking guidance for AROs in Section 35.18[3] of the Code of Federal Regulations:

> *"(a) A public utility that files a rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected*

[3] 18 C.F.R. §35.18

> *in rates, and must be removed from the rate base calculation through a single adjustment.*
>
> *(b) A public utility seeking to recover non rate base costs related to asset retirement costs in rates must provide, with its filing under §35.12 or §35.13, a detailed study supporting the amounts proposed to be collected in rates.*
>
> *(c) A public utility that has recorded asset retirement obligations on its books but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates."*

Q. DOES THIS MEAN THAT LEGAL REMOVAL COSTS ARE NOT RECOVERED FROM CUSTOMERS IN THE RATEMAKING PROCESS?

A. Not at all, and, in fact, quite the opposite. Regulated utilities are generally permitted to recover both reasonable and prudently incurred legal and non-legal removal costs in the ratemaking process through the previously described cost of removal methodology. As I stated, cost of removal expenditures are most often recovered from customers in advance of the actual expenditure through an estimated cost of removal concept. As a result, the ARC depreciation expense and ARO accretion that would be recognized in the income statement for a non-regulated entity are typically deferred as a regulatory asset for a regulated entity under ASC 980.

Q. ARE BOTH LEGAL AND NON-LEGAL REMOVAL COSTS ALWAYS RECOVERED VIA COST OF REMOVAL?

A. Generally yes, but not always. Decommissioning of nuclear plants is a common utility ARO where such costs are collected via a nuclear decommissioning surcharge, which operates differently from the traditional cost of removal concept. The point is that legal or non-legal removal/retirement costs that have been prudently incurred are recoverable from customers.

Once it is determined that a cost is prudently incurred and should be recovered, it is then up to the regulator to determine the method and period of recovery. This is an important point. Accounting does not drive cost recovery, but rather cost recovery drives the accounting under ASC 980.

Q. IS "COST OF REMOVAL ACCOUNTING" UNIVERSALLY APPLIED FOR "NORMAL" ASSET RETIREMENTS SUCH AS UTILITY POLES?

A. As I stated, cost of removal accounting is commonly used across the United States for determining revenue requirements. While the majority of regulators apply the ratemaking and accounting treatment for cost of removal as I have described, one outlier is the Pennsylvania Public Utility Commission, which has required certain jurisdictional utilities to capitalize incurred costs of removal as a regulatory asset after the removal occurs and has permitted recovery from customers over a future period. It has also required certain jurisdictional entities to capitalize the incurred costs of removal as part of the new asset being constructed and is depreciated/recovered over the life of the new asset. In either case, these costs are included in the rate base and earn a return as investors have financed these asset retirement costs. This example reinforces my primary assertion that for regulated entities, accounting follows ratemaking, not the other way around.

Q. DOES ASC 410 CONTAIN GUIDANCE ON THE RATEMAKING TREATMENT OF LEGAL ARO LIABILITIES OR NON-LEGAL COSTS OF REMOVAL?

A. No. ASC 410 and other FASB pronouncements do not address ratemaking treatment; ASC 980 addresses the accounting based on ratemaking treatment. However, ASC 410 acknowledges that many regulated entities recover asset retirement costs differently than how GAAP may recognize the related expense. Discussing rate-regulated entities, ASC 410 states:

> *"The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement, and, therefore, may result in a difference in the timing of recognition of period costs for financial reporting and rate-making purposes."*

ASC 410 further recognizes that if the requirements for ASC 980 are met, the rate-regulated entity would recognize for financial accounting purposes a regulatory asset or liability for the differences in timing of cost recognition (and related recovery from customers).

V. <u>COAL ASH MANAGEMENT</u>

Q. WHAT IS COAL ASH MANAGEMENT?

A. Coal combustion residuals (CCRs), or coal ash, is the waste from coal-fired power plants. Coal ash management or closure represents the costs necessary to handle and store the residuals from a coal generating facility in compliance with state and federal regulation.

Q. IN THIS PROCEEDING, ARE OTHER WITNESSES PRESENTING INFORMATION REGARDING COAL ASH?

A. Yes. Witness Timothy Hill explains the specifics of the Company's coal ash closure and management projects and related costs, including a history of how both the Federal and the Indiana environmental protection agencies have responded to and provided specific requirements relating to ensuring that responsible procedures are performed to protect the community from the environmental impacts associated with CCRs.

Q. HAS COAL ASH ALWAYS BEEN A KNOWN COST ASSOCIATED WITH REMOVING COAL GENERATION FACILITIES?

A. Yes, but the extent of these costs has dramatically changed in recent years.

Q. WERE SUCH COSTS INCLUDED AS A COST OF REMOVAL AND RECOVERED DURING THE LIVES OF THE COAL GENERATING FACILITIES THROUGH DEPRECIATION CHARGES?

A. Not always. It is my understanding that in many cases, the estimated cost of managing the coal ash remaining at retiring coal facilities were historically not considered significant and therefore, not included in related depreciation studies.

Q. HAS DUKE ENERGY INDIANA INCLUDED AN ESTIMATE FOR COAL ASH REMEDIATION AS COST OF REMOVAL IN THEIR PREVIOUS DEPRECIATION STUDIES?

A. Yes, in Cause No. 42359, the Company included a small estimate for the costs associated with remediating coal ash in the depreciation rates in effect from May 2004 through July 2020.

Q. WHAT CHANGED THAT SIGNIFICANTLY INCREASED THE COST TO REMEDIATE COAL ASH PRODUCED BY COAL GENERATION FACILITIES?

A. As is explained in more detail by witness Hill, the final rules regulating the safe disposal of CCR were provided by the EPA at the end of 2014. The rules provide a comprehensive set of requirements for the safe disposal of CCRs from coal-fired power plants that requiring approval under a state implementation plan under the purview of the Indiana Department of Environmental Management ("IDEM").

The rules establish the technical requirements for CCR landfills and surface impoundments addressing the risks from coal ash disposal - leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments.

Q. DID THE CCR RULES REQUIRE AN INCREASE IN THE ESTIMATED COSTS REQUIRED TO REMEDIATE COAL ASH FROM AN ELECTRIC GENERATING PLANT?

A. Yes. The CCR rules required Duke Energy Indiana to either remove coal ash from its properties or leave the coal ash in place, covered by an impermeable cap, and monitored for up to thirty years, thereby increasing estimated costs substantially over the amount included in the previous depreciation study.

Q. DID DUKE ENERGY INDIANA REQUEST RECOVERY OF ANY OF THE REVISED COSTS IN THEIR 2019 RATE CASE?

A. Yes.

Q. IN THAT CASE, WERE SUCH COSTS INCLUDED AS COST OF REMOVAL AND DEBITED TO ACCUMULATED DEPRECIATION?

A. No. Duke Energy Indiana recorded federally mandated legal obligations using the accounting for such costs under ASC 410. Approximately $257 million of such costs actually incurred from 2015 to 2018 were deferred as a regulatory asset when expended and the Company included the regulatory asset in rate base and amortization of the regulatory asset as a cost of service in its 2019 rate case. The Commission approved both recovery of the amortization and a return on the unrecovered regulatory asset. However, the Indiana Supreme Court reversed this recovery under a theory of impermissible retroactive ratemaking.

Q. HOW DID DUKE ENERGY INDIANA ACCOUNT FOR THIS DECISION?

A. As the $257 million regulatory asset for CCR remediation was no longer probable of future recovery, Duke Energy Indiana wrote-off this amount to expense for accounting purposes.

Q. IS DUKE ENERGY INDIANA SEEKING RECOVERY OF ANY OF THE COAL ASH COSTS THEY HAD INCLUDED IN THE 2019 RATE CASE FILING THAT WERE REVERSED BY THE INDIANA SUPREME COURT?

A. No. It is my understanding that Duke Energy Indiana is not seeking recovery of or return on such amounts in this rate case.

Q. HAS DUKE ENERGY INDIANA SOUGHT RECOVERY OF ANY OTHER COAL ASH COSTS SINCE THE 2019 RATE CASE FILING?

A. Yes. As discussed by witness Hill, in Cause No. 45253 S1, Duke Energy Indiana received a certificate of public convenience and necessity ("CPCN") that would authorize a return on and of recovery under the Federal Mandate Statute of certain coal ash remediation costs. Approximately $92 million of CCR costs had been incurred and deferred into a regulatory asset between January 1, 2019, and November 3, 2021 (the date of the grant of the CPCN); however, the CPCN issued by the Commission was subsequently reversed as to these pre-Order costs by an Indiana Court of Appeals decision.

In Cause No. 45253, the Company was also granted recovery of a return on and recovery of approximately $2.399 million of CCR costs forecasted to be incurred for Dresser and Gibson East after the date of the Order. The 2022 Indiana Supreme Court decision did not impact the post-Order amortization and rate recovery of these costs.

Finally, in Cause No. 45940, Duke Energy Indiana has requested a CPCN under the Federal Mandate Statute, as amended, that would provide recovery of a return of and on approximately $327 million in costs incurred and to be incurred for coal ash remediation at Gallagher, Wabash River, Gibson North and South, and legacy Edwardsport Stations. As of the filing of this testimony, that Cause remains pending.

Q. WHAT CCR COSTS IS DUKE ENERGY INDIANA INCLUDING IN THIS PROCEEDING?

A. As explained by witness Hill, Duke Energy Indiana has included estimated future coal ash-related costs in the Company's 2023 decommissioning study. Those costs include:

- Closure costs for future closures of the Company's CCR Units not previously included in Cause Nos. 45253 S1 and 45940.
- In addition, in this proceeding, the Company is requesting that the Commission reflect in the calculation of depreciation rates the $92 million in costs incurred between January 1, 2019, and November 3, 2021, which were authorized by the CPCN under the Federal Mandate Statute that was later reversed by an Indiana Court of Appeals decision. Witness Hill supports the prudency and reasonableness of these costs, and Witness Spanos explains that they have been reflected in the calculation of his recommended depreciation accrual rates.

Q. CAN YOU PLEASE QUANTIFY THE AMOUNTS OF THE ASH POND COSTS THE COMPANY IS INCLUDING IN THIS PROCEEDING?

A. Yes. The CCR Ash Pond costs requested are as follows:

Future CCR Closures	$131.4 million
Cause 45253 Pre-Order Costs	$92.1 million
Total:	$223.5 million

How these estimated costs were derived as well as the current status of each category (by Generating Station) are further explained in witness Hill's testimony.

Q. WHAT METHOD IS DUKE ENERGY INDIANA USING TO RECOVER THE ABOVE COSTS IN THIS PROCEEDING?

A. The costs included above have been accounted for using the traditional cost of removal accounting that I previously described and charged to Accumulated Depreciation or included as the cost of removal component of annual depreciation rate accruals.

Q. IS COST OF REMOVAL ACCOUNTING/RECOVERY APPROPRIATE FOR THIS ESTIMATED COST?

A. The previously described cost of removal accounting procedure is appropriate from a regulatory standpoint for prudently incurred costs to remediate coal ash in order to comply with the CCR requirements. As I stated, with any cost of removal, the eventual cost is estimated and included as a component of depreciation expense and trued-up when actual expenditures are made. As Duke Energy Indiana had previously been accruing for cost of removal for coal ash in Cause No. 42359 (albeit at a lower estimated amount), changes in estimates are not uncommon and by charging CCR expenditures to Accumulated Depreciation and adjusting future depreciation accrual rates, such amounts will be recovered from customers.

Q. ARE YOU FAMILIAR WITH HOW OTHER INDIANA UTILITIES HAVE ACCOUNTED FOR AND RECOVERED CCR REMEDIATION COSTS?

A. It is my understanding that several other Indiana utilities with CCR remediation cost requirements have followed cost of removal accounting and are recovering such costs as a component of depreciation expense, not different than other costs (legal or non-legal removal/retirement costs). It is my understanding that others are using the Federal Mandate Statute.

Q. DO YOU SUPPORT THIS APPROACH?

A. Yes. Under traditional rate regulation capital costs, both the prudently incurred initial cost of acquisition/construction as well as the necessary postretirement costs represent costs to be recovered in the ratemaking process. Investors are entitled to recovery of such costs (typically through depreciation charges during the fixed asset life or afterwards if actual removal costs are more or less than what was originally estimated). The FERC USoA accommodates this methodology through a combination of group depreciation, cost of removal and acceptance of depreciation accruals resulting from depreciation studies. Such studies include estimated lives and removal costs and are trued-up to actual amounts with differences between actual and estimated amounts typically considered prospectively (adjusted for) in subsequent depreciation studies.

Q. ARE YOU FAMILIAR WITH THE IURC'S DECISION IN CENTERPOINT ENERGY INDIANA SOUTH'S REQUEST FOR RECOVERY OF SIMILAR COAL ASH COSTS?

A. Yes. In that Cause, the IURC referenced Ind. Code 8-1-8.4.7(c). That section of the Indiana Code provides in part:

> *"If the Commission approves under subsection (b) a compliance project and the federally mandated costs associated with the 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. …*
>
> (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."*

In Cause No. 45903, CenterPoint Energy Indiana South ("CEI South") requested a CPCN for recovery of closure by removal ("CBR") costs. In that Cause, the IURC concluded:

> *"Based on the evidence of record, we find that the CBR Project will allow CEI South to comply with the CCR Rule (a federally mandated requirement), and thus the public convenience and necessity requires the CBR Project….*[4]
>
> *Therefore, based on the law and evidence of record, we approve the CBR Project pursuant to the Federally Mandate Statute and grant CEI South's request for a CPCN on the CBR Project."*

The IURC Ordered:

> *"5. CEI South is authorized to timely recover 80% of the approved federally mandated costs incurred in connection with the CBR Project through its*

[4] *CEI South,* Cause No. 45903 (IURC 2/7/2024), p. 13.

existing ECA mechanism pursuant to Ind. Code 8-1-8.4-7 including capital, O&M, depreciation, taxes, financing, and carrying costs based on its weighted cost of capital, as described above.

6. CEI South is authorized to accrue post-in-service carrying charges based upon CEI South's WACC on the federally mandated costs for the period between when costs are incurred for the CBR Project and when such costs are included for recovery in rates through the ECA.

…

8. CEI South is authorized to defer 20% of the federally mandated costs incurred in connection with the CBR Project for recovery in its next general rate case, as described in Finding Paragraph 4.B.i.

9. CEI South is authorized to record post-in-service carry charges authorized herein until completion of the CBR Project as RWIP within Account 108 and after completion as a regulatory asset in Account 182.3 Other Regulatory Assets."[5]

Q. IS THERE ANYTHING ELSE IN THAT ORDER THAT SHOULD BE CONSIDERED IN THIS PROCEEDING?

A. Yes. The Commission states the following:

"We agree with CEI South that costs of removal are appropriately considered capital costs in connection with the Federal Mandate Statute.

[5] *Id.,* p, 17.

> *While OUCC witness Blakley is correct that one avenue for recovery of CCR remediation costs is a general rate case, that does not render them ineligible for recovery under the Federal Mandate Statute.*
>
> *The OUCC also argues that costs of removal are more appropriately recovered through normal retirements and removal accounting, debiting Account 108 for costs and including them in future depreciation accrual rates. Again, we find that, even though this is a valid form of recovery, it does not prevent CEI South from pursuing recovery for which it is eligible under the Federal Mandate Statute, as it has done here."*[6]

As I have testified, cost of removal treatment is what Duke Energy Indiana is proposing in this case and is the recovery methodology traditionally used for such costs under traditional ratemaking and used by other Indiana rate-regulated utilities. However, I understand that the Federal Mandate approach is another approved method within the State of Indiana; thus both methods should be considered available for use by the Company.

Q. YOU MENTIONED PREVIOUSLY THAT DUKE ENERGY INDIANA HAS PENDING IN CAUSE NO. 45940 A REQUEST FOR A CPCN UNDER THE FEDERAL MANDATE STATUTE THAT HAS NOT BEEN RESOLVED BY THE COMMISSION. TO THE EXTENT THE REQUESTED CPCN IS NOT GRANTED, HOW WOULD DUKE ENERGY INDIANA PROPOSE TO ADDRESS RECOVERY OF SUCH COSTS?

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[6] *Id.,* pp. 10-11.

A. In Duke Energy Indiana's next general rate case, it would propose new depreciation accrual rates that would reflect the costs incurred and to be incurred as cost of removal, similar to what is proposed here with respect to the Cause No. 45253 S1 costs incurred before November 3, 2021. This is consistent with the treatment requested by witness Mr. Davey in Cause No. 45940.

VI. CONCLUSION

Q. MR. RILEY, CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY AND THE CONCLUSIONS YOU HAVE REACHED?

A. Yes. Regulators generally approve the recovery of prudently incurred PP&E as well as post-closure costs through depreciation charges. Such expenditures are sourced from investors who are entitled to recover their investment plus a return on unrecovered amounts. The vehicle for recovery of post-closure costs is referred to as "cost of removal accounting" which allows regulated entities to accrue "removal cost depreciation" expense to match amounts allowed in revenues (i.e., amounts are collected in advance of the cash expenditure for remediation), or recovery of such cash expenditures after they are made. Amounts collected in advance of expenditures are typically recorded in accumulated depreciation, which reduces rate base recognizing that customers have supplied the advanced funding of removal costs, while expenditures incurred prior to recovery are recorded as a reduction to accumulated depreciation (or addition to a separate regulatory asset absent cost of removal accounting); these expenditure outflows accrue a return via increase to rate base or separately through regulatory asset (carrying charges) until recovery from ratepayers. Duke Energy Indiana's accounting and depreciation practices as detailed in my testimony appear to be consistent with the treatment for such costs afforded other Indiana utilities, GAAP, FERC USoA, and historical practices with regards to regulated utilities.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Cause No. 46038

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: Sean P. Riley ______________________

Sean P. Riley

Dated: April 4, 2024